Commonwealth of Massachusetts

Office of Consumer Affairs and Business Regulation

Market Monitor 1999
A Report by the Division of Energy Resources

An Annual Report to the Great and General Court on the Status of Restructured Electricity Markets in Massachusetts

February 2001

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ACKNOWLEDGEMENTS

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Please feel free to convey to the contributors listed above your reaction to this report and your thoughts with respect to future annual electric price, disparity and reliability reports.

This report is also posted on DOER's website at http://www.state.ma.us/doer.

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EXECUTIVE SUMMARY

During the twelve-month period ending in December 1999, the electric utility industry in Massachusetts continued its progress toward reliance on competitive markets. Transitional rate reductions mandated by the restructuring legislation resulted in $535 million saved by Massachusetts electric customers. In addition, wholesale electricity markets underwent a major transformation as the market for "spot" or daily wholesale transactions shifted from a cost-based to a bid-based system. In this Executive Summary, the Division of Energy Resources outlines the highlights and significant events of 1999.

The Restructuring Act requires the Division of Energy Resources (DOER) to monitor the changes in the electric industry each year. As prescribed by the Legislature, DOER reports on electricity prices and price disparities, competitive market developments, and electric system reliability (M.G.L. c.25A §§ 7, 11D, 11E). Below are the major findings for calendar year 1999.

1999 HIGHLIGHTS

1. Consumers Saved $535 Million In 1999.
As mandated by the Act, each local distribution company met the required fifteen percent rate reduction by September 1999. Massachusetts customers saved over $535 million over pre-restructuring rates. Over the course of the year, residential customers saved $200 million, commercial customers $251 million, and industrial customers $78 million. Individual savings averaged $92, $900, and $9,910 for residential, commercial, and industrial customers, respectively. When added to the savings realized in 1998, total savings after twenty-two months of restructuring equals $910 million.

2. Massachusetts Enjoyed the 4th Highest Savings Among Deregulated States.
For 1999, Massachusetts ranked 4th highest in percent price reduction among deregulated states. Of the 21 deregulated states and the District of Columbia, only Pennsylvania, Rhode Island, and Illinois showed greater percent rate decreases than Massachusetts. Stimulated by the five percent rate cut mandated by the Restructuring Act, ratepayers saved an average of six percent over 1998 prices.

3. The Number of Default Service Customers Increased.
In 1999, the percentage of Massachusetts customers receiving default service grew from 13.2 percent to 19.0 percent, an increase of 146,070 customers. Despite the fact that default service customers are supposed to receive market-priced power, default rates continued to be priced below market at standard offer levels. As a consequence, some utilities accumulated costs to serve default service customers that will have to be recovered at a later date.

4. The Number of Customers Served by Competitive Suppliers Grew Slowly.
As in 1998, the competitive retail market for electricity grew slowly in 1999. At the end of 1999, only 9,009 of nearly 2.5 million Massachusetts customers had switched to a competitive supplier. Low standard offer and default service rates, and immature wholesale electricity markets contributed to minimal competition. Even though the number of licensed suppliers increased, few retail electricity products were available in 1999.

5. Price Disparities Did Not Change Dramatically.
Despite statewide rate reductions, price disparities among the Commonwealth's distribution companies experienced no significant changes. Substantial differences in rates existed between the different service territories. In addition, the data indicate that customer rates continued to vary among customer sectors—on average, residential customers pay the highest electric rates, and industrial customers the lowest.

6. Merger Activity Changed the Retail Market Landscape.
Following substantial changes in the ownership of generating plants in 1998, there was unprecedented merger activity among distribution companies in 1999. In the pursuit of increased efficiency, greater market share, and broader service territories, local distribution companies in Massachusetts joined with each other to form bigger corporations. Three mergers saw activity in 1999: BEC Energy and Commonwealth Energy joined to form NSTAR, New England Electric Systems merged with the National Grid Group from England, and Eastern Utilities was acquired by New England Electric Systems.

7. Wholesale "Spot" Markets Shifted to Competitive Bidding.
On May 1, 1999, the Independent System Operator of New England (ISO-NE) initiated a bid-based "spot" market for wholesale electricity and energy products. In the spot market, electricity is bought and sold on an hourly basis at market prices. The new competitive system was intended to stimulate competition for wholesale electricity and keep prices low. Early experience revealed significant increases in price volatility and pointed to a need for additional market reforms.

8. Large Commercial and Industrial Customers Opted for Competitive Supply.
The large customers that switched to a competitive supplier tended to have higher electricity usage than the average usage in their customer sector. For instance, the large commercial and industrial (C&I) customer who entered the competitive market used on average 429,161 kWh in December compared to standard offer and default service large C&I customers who used on average 232,266 and 138,006 kWh, respectively. Of the electricity sold by competitive suppliers in December of 1999, large C&I customers bought 87 percent, or roughly 280 million of 322 million kilowatt-hours sold.

9. Wholesale Power Grid Reliability Tested During Summer Months.
On June 8th and 9th, New England experienced unseasonably warm weather resulting in a significant test of the electric grid's reliability. Demand for electricity approached maximum capacity. However, through the implementation of emergency procedures, the Independent System Operator of New England was able to avert rolling blackouts and other service disruptions. This event underscored the need for increased generation capacity and energy conservation in New England. Fortunately, conservative projections indicate that future capacity should meet growing demand.

1999 MARKET MONITOR REPORT FOCUS

This is DOER's second annual assessment of the specific results of electric utility restructuring in Massachusetts. It includes a discussion of prices and price disparities for each customer sector in Massachusetts. DOER has also placed Massachusetts electricity prices within the context of the United States. An analysis of customer migration to competitive service and details of developments in the wholesale industry are also included. An outlook of issues to be addressed in the 2000 Market Monitor concludes this report.

REPORT OUTLINE

Chapter I introduces the themes of this report and offers a broad set of observations about the emerging electricity markets in Massachusetts.

Chapter II includes a review of price and price disparity data from all distribution companies. Price information shows evidence of the mandated fifteen percent rate reduction for all distribution company customers. This chapter concludes by comparing electricity prices in Massachusetts to those in other states in New England and the United States.

Chapter III provides a review of competitive retail market developments in 1999. Data collected by DOER is presented to show how customers have moved among standard offer, default service, and competitive supply. This chapter discusses developments designed to stimulate increased competition in these markets. In addition, DOER presents an account of utility merger activities in 1999.

Chapter IV shifts the focus of the report to the wholesale side of the electric industry. In this chapter, attention is given to the development of a wholesale "spot" market for electricity and the new roles of the New England Power Pool and the Independent System Operator of New England. Lastly, this chapter includes a discussion of reliability issues.

Chapter V previews issues and events to be covered in the 2000 Market Monitor Report.

CHAPTER I: THE YEAR 1999

In 1999, restructured electricity markets continued to evolve at a modest pace. While marking notable progress, the establishment of a fully competitive retail electricity market in Massachusetts remains an unrealized goal. In this report, the Massachusetts Division of Energy Resources (DOER) details the progress of the transition to a competitive market during the second year of electric utility restructuring.

Ultimately, the goal of the 1997 Electric Restructuring Act[1] is to provide retail choice of electricity to all customers and produce full and fair competition in the electricity generation market. To achieve this goal, many structural changes are needed at both the retail and wholesale levels. Many of the necessary changes took place in 1998. This report examines further restructuring changes and the resulting impacts on Massachusetts' electricity prices and price disparities, the development of competitive markets, and electric system reliability; and then compares these changes to the goals of The Act:

- Create lower electric prices for Massachusetts' residents and businesses;
- Ensure full and fair competition in electricity generation;
- Provide retail choice of suppliers to all customers;
- Maintain system reliability and improve distribution performance;
- Enhance public benefits such as low-income discounts, energy efficiency, and the expansion of renewable energy;
- Ensure consumer protection and education; and
- Provide orderly and expeditious transition to competitive markets.

As mandated by The Act, Massachusetts ratepayers saw additional savings on their electric bills. Standard offer and default service customers saved on average an additional six percent on electricity generation over and above the ten percent savings of their 1998 bills. However, artificially low standard offer and default service rates made it difficult for suppliers to develop products that were both profitable and competitive. In 1999, there was only modest customer migration toward competitive electricity suppliers.

Also in 1999, electricity generation began operating as a market in New England, bringing with it a new set of rules and more than a few tribulations. The Independent System Operator of New England (ISO-NE) administers this new wholesale market. Even during the transition to the wholesale market, the New England power grid retained a high degree of reliability.

Three topical chapters comprise the 1999 Market Monitor Report: Chapter II contains an analysis of 1999 retail electricity prices in Massachusetts. These prices are examined by rate class, and compared to prices in other deregulated states. Chapter III explores developments in the competitive retail market, and includes data for each service territory. Chapter IV explains the revolutionary changes in New England wholesale electricity mechanisms. This report concludes with a brief list and summary of topics for next year's report.

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[1] *Chapter 164 of the Acts of 1997: An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, And Promoting Enhanced Consumer Protection Therein.* [hereinafter the Act].

CHAPTER II: PRICES AND PRICE DISPARITIES

During 1999, electricity prices for Massachusetts residents and businesses decreased from 1998 levels, fulfilling one of the basic goals of the Act. A detailed review of the price decreases is presented below. The first five sections of this chapter provide a discussion of prices among the eight Massachusetts investor-owned distribution companies, including analyses of price disparities, residential discount customers, and unbundled residential bill components. In the final three sections, Massachusetts prices are placed in a regional and national context.

2.1 Electric Distribution Companies in Massachusetts -- Overall Prices

Prices decreased on average by six percent due to the mandated rate reductions.

In 1999, eight investor-owned local distribution companies (LDCs) and forty publicly-owned municipal utilities, each with a distinct service territory (as highlighted in the 1998 report)[2] served Massachusetts customers. The LDCs are Boston Edison, Cambridge Electric, Commonwealth Electric, Eastern Edison, Fitchburg Gas and Electric Light, Massachusetts Electric, Nantucket Electric, and Western Massachusetts Electric. Table 1 compares 1998 prices to 1999 prices for each investor-owned distribution company and the weighted-average price for municipal utilities.

Table 1: Average Price per kWh for Electric Companies in Massachusetts[3]

Distribution Company	1999 Average Price (cents/kWh)	1998 Average Price (cents/kWh)	Change
Boston Edison	10.1	10.5	-4.1%
Cambridge Electric	7.6	8.1	-6.7%
Commonwealth Electric	10.5	11.1	-5.0%
Eastern Edison	8.6	9.2	-5.8%
Fitchburg Gas & Electric	10.4	10.5	-1.4%
Massachusetts Electric	7.8	8.9	-11.6%
Nantucket Electric	11.8	12.7	-6.7%
Western Massachusetts Electric	9.2	9.5	-2.5%
Total: Distribution Companies	9.0	9.6	-6.8%
Total: Municipal Companies	9.0	9.3	-3.0%
TOTAL OF ENTIRE STATE	9.0	9.6	-6.3%

Sources: FERC Form 1, EIA 826, Municipal Reports to DTE, 1998 Market Monitor

[2] Division of Energy Resources, Market Monitor 1998. September 1999. Page 4.

[3] Percentage changes in this and other tables may not correspond exactly to accompanying data due to rounding.

The data show that prices fell statewide by an average of 6.3 percent, a decrease largely attributable to mandated rate reductions discussed below. Table 1 also illustrates the variation of price decreases among the different distribution companies. Specific reasons for these differences are due, in part, to differences in service territories and customer mix, as well as the companies' use of different price inflation adjustments (e.g. Boston Edison) and differences in rate changes throughout the year (e.g. Eastern Edison and Fitchburg Gas & Electric).

LDCs have closed the price gap with municipal utilities.

In 1998, municipal utilities offered lower prices, on average, than the LDCs. The data presented in Table 1 suggest that in 1999 municipal utilities and local distribution companies had equal average prices. Both LDCs and municipal utilities showed rate decreases in 1999, but the private utilities delivered larger rate cuts. This narrowing of price differentials between municipal utilities and the LDCs may reflect the fact that mandated rate reductions applied only to the LDCs.

2.2 Mandated Rate Reductions

September 1, 1999 rates were fifteen percent lower than the inflation-adjusted reference rates.

As required by the Act, each Massachusetts investor-owned distribution company provided a rate reduction of at least ten percent on customer bills beginning March 1, 1998. This discount was provided to all customers of record as of that date. The 1998 Market Monitor illustrated the ten percent rate reduction of March 1998 for three typical customers. For each customer sector, the data showed that all distribution companies complied with the Act.

The Act further required that the total rate reduction, including the March 1998 ten percent rate reduction, be fifteen percent on or before September 1, 1999. However, the Act allowed companies to adjust rates for inflation from the rates as of August 1997 or another date that the Department of Telecommunications and Energy (DTE) determined as representative of 1997 rates for a company. Though only applicable to standard offer rates as a matter of policy, default service rates were kept equal to standard offer rates in 1999, effectively leading to identical rate reductions in 1999 for both standard offer and default service customers.[4]

All companies' rate schedules for September 1, 1999 to December 31, 1999 provided "each and every retail customer with an inflation-adjusted rate reduction of at least fifteen percent for electricity consumption on or after September 1, 1999."[5]

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[4] On August 17, 1999, the DTE issued a letter order with guidelines for the LDCs in setting and implementing the 15 percent rate reduction. All distribution companies filed compliance filings illustrating these reductions in detail. However, subsequent to this order and these filings, the DTE amended their order in a December 17, 1999 order, which only required rate reductions for "each customer class" instead of "each retail customer." The 2000 Market Monitor Report will present the impacts of the December 17, 1999 order on year 2000 prices.
[5] Department of Telecommunications and Energy. Request for Tariff Filing. August 19, 1999.

Table 2 provides an example of a residential customer using 500 kWh per month. The analysis indicates that September 1, 1999 rates were fifteen percent lower than the inflation-adjusted reference rates. In some service territories, the discounts exceeded the mandated minimum.

Table 2: Fifteen Percent Rate Reduction on Monthly Electricity Bill
Residential Customer, 500kWh

Distribution Company	Aug. 97 $	Sept.99 $	Real Savings $	%
Boston Edison	71.59	60.72	10.87	15.2
Cambridge Electric	62.51	51.13	11.38	18.2
Commonwealth Electric	73.68	62.64	11.05	15.0
Eastern Edison	59.67	50.02	9.66	16.2
Fitchburg Gas & Electric	66.24	56.29	9.95	15.0
Massachusetts Electric	57.63	48.31	9.33	16.2
Western Massachusetts Electric	65.33	55.54	9.79	15.0

Source: Distribution Company Tariff Filings, DOER

In Table 3, residential customer bills are compared between August 1999 and September 1999. This table demonstrates that, although each LDC met the requirements set forth in the Act, nominal savings (amounts actually paid by customers) were lower than five percent.

Table 3: Analysis of Monthly Bills, August 1999 to September 1999
Residential Customer, 500 kWh

Distribution Company	Aug. 99 $	Sept. 99 $	Bill Savings $	%
Boston Edison	61.79	60.72	1.07	1.7
Cambridge Electric	51.26	51.13	0.13	0.3
Commonwealth Electric	62.75	62.64	0.12	0.2
Eastern Edison	50.91	50.02	0.90	1.8
Fitchburg Gas & Electric	54.80	56.29	-1.49	-2.7
Massachusetts Electric	49.07	48.31	0.76	1.5
Western Massachusetts Electric	56.60	55.54	1.06	1.9

Source: Distribution Company Tariff Filings, DOER

Customers saved $535 million in 1999 for a total savings of $910 million since March 1998.

Table 4 presents cumulative savings from mandated rate reductions from March 1998 through December 1999.[6] The estimates in Table 4 can be considered conservative. Calculations were conducted on the broad customer categories shown in the table, and there was no attempt to measure the savings due to migration of customers, who presumably switched to competitive suppliers that were able to provide even greater savings. Average 1999 savings per residential, commercial, and industrial customer were $92, $900, and $9,910 respectively.

Table 4: Savings from Mandated Rate Reductions
1998-1999 ($ in millions)

	Residential $	Commercial $	Industrial $	Other $	All Customers $
March-December 1998	141.5	160.1	65.2	8.6	375.4
January-August 1999	114.3	143.4	44.5	3.7	305.9
September-December 1999	85.7	107.5	33.4	2.8	229.4
1999 Totals	200.0	250.9	77.9	6.5	535.3
Totals, All Years	341.5	411.0	143.1	15.1	910.7

Source: DOER, 1998 Market Monitor; EIA

2.3 Price Disparity by Customer Sector

Restructuring did not affect the differences among prices charged by the different LDCs.

As was true in 1998, restructuring did not alter price disparities among the distribution companies when 1999 prices were examined at an aggregated level. That is, restructuring did not affect (to a statistically significant degree) the differences among prices charged by the different distribution companies.

This report examines price disparity using the data in Table 5. The data highlight both the price differences among the customer sectors and among the distribution companies. With one exception (Nantucket Electric), residential prices remained the highest among customer sectors, while industrial prices were lowest.

Within each sector, the price differences were less pronounced in a comparison among the different distribution companies. For example, residential prices ranged from 8.9 (Mass. Electric) to 11.9 (Fitchburg G&E) cents per kWh compared to differences among customer sectors for particular companies, which featured wider ranges.

[6] As calculated in the 1998 Market Monitor, Massachusetts customers saved approximately $450 million in the year following the March 1998 rate reduction.

Table 5: 1998 and 1999 Price Levels for Distribution Companies
(cents/kWh)

Distribution Company	Residential			Small Commercial or Industrial			Large Commercial or Industrial		
	1999	1998	Change	1999	1998	Change	1999	1998	Change
Boston Edison	11.8	12.0	-1.5%	9.4	10.0	-5.7%	8.9	9.2	-3.6%
Cambridge Electric	10.8	11.5	-5.8%	7.1	7.6	-6.9%	6.4	7.0	-7.6%
Commonwealth Electric	11.9	12.5	-4.8%	9.5	10.0	-5.1%	7.7	8.5	-8.5%
Eastern Edison	9.3	9.8	-5.2%	8.0	8.6	-6.2%	7.9	8.5	-7.2%
Fitchburg Gas & Electric	11.9	11.9	-0.4%	11.3	11.8	-4.3%	8.9	8.9	-0.8%
Massachusetts Electric	8.9	9.7	-8.1%	7.5	8.7	-13.2%	6.4	7.7	-16.4
Nantucket Electric	11.5	12.3	-7.2%	12.4	13.2	-5.6%	17.5	18.3	-4.2%
Western Massachusetts Electric	10.5	10.8	-2.8%	9.0	9.3	-3.2%	7.5	7.7	-1.9%

Source: FERC Form 1, EIA 286

Though analysis of the raw data in Table 5 is useful, it is more accurate to examine the variance in the price disparity calculations in Table 6. Table 6 shows the disparity calculation using Table 5 data weighted by kWh sales. 1998 data were taken from the 1998 Market Monitor. Overall, price disparity increased from 2.3 to 2.4 cents per kWh, a statistically insignificant difference.[7]

Table 6: 1998 and 1999 Price Disparity of Customer Sectors (cents/kWh)

	1999	1998
Residential	1.7	1.5
Commercial	4.0	3.7
Industrial*	1.2	0.6
Overall	2.4	2.3

*Excludes Nantucket Electric Data

Sources: 1998 Market Monitor, FERC Form 1, EIA-286, DOER

Though not shown in the table, there were greater differences among the prices for the industrial customer group (after removal of Nantucket Electric as an outlier). This can be explained by examining the data in Table 5. Because the price disparity of Table 6 used weighted values, Massachusetts Electric rate changes, which were quite different from the other LDCs, received proportionately the greatest weight. Consequently, there was an increase in price disparity for that customer group after the removal of Nantucket Electric.

[7] Applying the F-Test to the unweighted data yield the following probabilities that price disparity **did not** change: 86 percent for Residential, 99 percent for Commercial, and 98 percent for Industrial.

2.4 Electric Discount Rate for Income-Eligible Customers

Under the Act, the Massachusetts Legislature increased the income eligibility level for the electric residential discount rate (RDR).[8] An RDR eligible (RDRE) household:

- Receives a means-tested public benefit or qualifies for assistance through the Low-Income Home Energy Assistance Program (LIHEAP); <u>and</u>
- Has a total household income of no more than 175 percent of the federal poverty level.[9]

The Act requires each distribution company to conduct substantial outreach and to report to DOER at least annually on its activities and results.[10]

DOER published outreach guidelines.

In accordance with the Act, DOER published *The Low-Income Outreach Guidelines* in December of 1998.[11] The guidelines assist distribution companies in the development of effective procedures for identifying RDRE households and enrolling them as RDR customers. The *Outreach Guidelines* require each distribution company to:

- Work with the Department of Revenue's Child Support Division to inform their clients of the availability of the discount;
- Adopt "Discount Rate" as the new name for the low-income rate;
- Change all financial hardship forms to reflect the new name;
- Provide quarterly notification via bill stuffers and newsletters of the availability of the discount rate;
- Set up point-of-purchase displays with state and federal agencies that offer qualifying benefits;
- Work with schools/camps to reach families in the Head Start and National School Breakfast and Lunch Programs; and,
- Establish a separate toll-free telephone number for discount rate inquiries.

Only 27 percent of RDRE households received the discount rate.

The distribution companies filed their first annual reports with DOER in 1999. The reports included data on the number of RDR customers in 1997 (pre-deregulation), 1998, and 1999. A year-to-year comparison shows first a drop in RDR enrollment from 1997 to 1998, which has been attributed to the many demands of the initial year of the Act's implementation. Figure 1 illustrates that, while progress was made in signing customers up for the discount rate in 1999 from 1998, the numbers were still only slightly higher than the pre-deregulation levels of 1997 before the income eligibility level increased.

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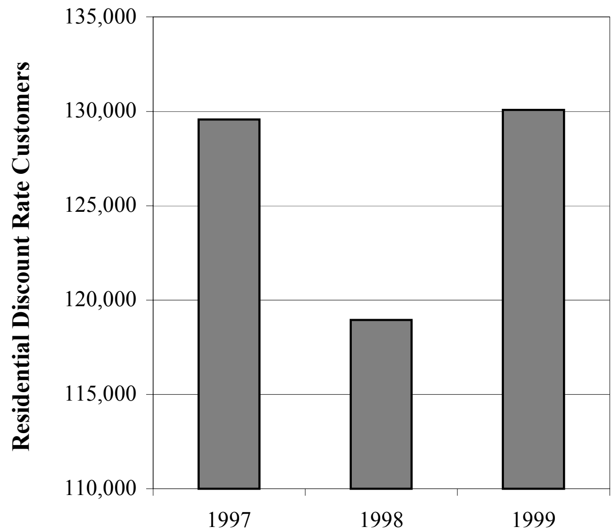
[8] The Act, M.G.L. Ch.164 §1F(4)(i)
[9] Id.
[10] Id.
[11] Id.

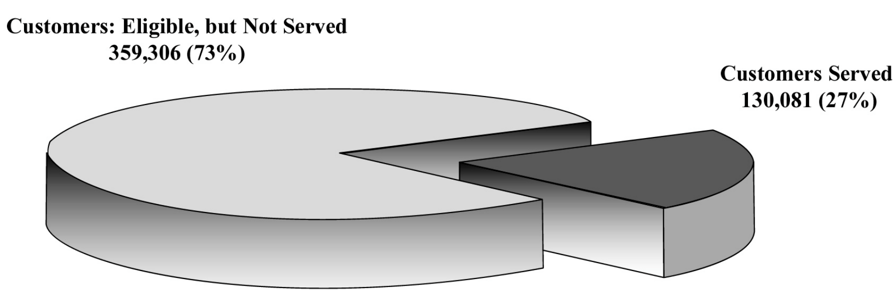
Figure 1: Residential Discount Rate Customers, 1997-1999



Source: Distribution Company Filings with DOER

When compared to the DOER estimate of the total 1999 RDRE households (489,387), the distribution companies' reported figures[12] show that approximately 27 percent were enrolled as RDR customers (see Figure 2). These low enrollment levels suggest that more needs to be done. Consequently, DOER will be reviewing its guidelines and will be working with stakeholders to identify procedural barriers to enrollment. DOER plans to file revised outreach guidelines with the DTE in 2001.

Figure 2: 1999 Percentage of Residential Discount Rate Eligible Households Served



Source: DOER (see footnote)

[12] The 1999 DOER Income Eligible Households figures were derived by using the following formula. The 1998-1999 MISER Low-Income Eligible Households in Massachusetts at 175 percent of the Federal Poverty Level minus the 13 percent of that population in municipal utilities' territories, multiplied by the 1990 Census Percentage of the Eligible Households at 175 percent of the Federal Poverty Level for each distribution company. This same formula was used for the Energy Efficiency Income Eligible Households Figure in DOER's **1999 Energy Efficiency Report.**

2.5 Unbundled Residential Bill Component Price Analysis

In addition to rate reductions, the Act also required distribution companies to unbundle bills, itemizing delivery-related service charges and supplier-related service charges.[13] As mentioned above, default and standard offer prices did not differ from each other during 1999, hence there is no distinction between the two in the discussion below.

Rate schedules did not go through massive changes but were modified (by distribution companies) in similar, though not identical, orders of magnitude due to inflation-related adjustments. This report section provides additional rate disparity analysis by comparing and contrasting, for residential customers, the rate structures (rather than the prices for a particular usage level), for each distribution company and the changes to rates over the year 1999.[14]

The residential rates found in Table 7 are for R-1 customers who do not have electric space heating. Unlike the C&I customer classes, there is much more uniformity in the rate class definitions for residential customers among the distribution companies, thus making a comparison more valid.

The generation portion of the retail bill increased.

In January 1999, the standard offer and default service generation rates and transition (stranded cost) charges for each LDC were adjusted from those rates established in 1998. This process is commonly referred to as "true up." Each company at the end of the calendar year submits a filing to DTE that reports the reconciliation of the company's estimated annual revenues and costs to the actual revenues and costs for that year. At the same time each company submits its standard offer generation and transition charges for the next year.

In the restructuring rate schedules for most of the distribution companies, the standard offer price for generation will gradually increase over seven years. The original trajectory is as follows: 2.8 cents/kWh in 1998, 3.1 cents/kWh in 1999, 3.8 cents/kWh in 2000 and 2001, 4.2 cents/kWh in 2003, 4.7 cents/kWh in 2004, and 5.1 cents/kWh in 2004. Due to several factors, but mainly the quick reductions in transition charges in the early years of restructuring, all the companies have been able to solicit a rate for generation more closely reflective of competitive wholesale prices (i.e. higher) than originally proposed.[15] For example, the settlement schedule called for a standard offer generation rate of 3.1 cents/kWh in 1999. All but one company offered a higher rate during that year. Higher standard offer rates increased the ability of competitive suppliers to meet or beat that rate. In addition, most companies had only one change in the standard offer rate during 1999.

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[13] Delivery-related charges include: Customer, Distribution, Transition, Transmission, Energy Efficiency, and Renewable Energy charges. Supplier-related charges are standard offer, default service, or competitive generation. See 1998 Market Monitor for a more detailed description.

[14] Any analysis of differences among LDCs in terms of their rate structures should be done on a broad, company-wide basis. Isolating particular customer groups of classes may distort conclusions due to the differing rate structures and customer bases that are used to calculate company revenues.

[15] At the end of 1998, the distribution companies had either completed or were in the process of completing the divestiture of non-nuclear generation assets. The sales resulted in nearly a 30 percent reduction in stranded costs statewide.

Table 7: Residential Customer R-1 Rate Structures, 1999

	Boston Ediston	Cambridge Electric	Comm Electric	Eastern Edison	Fitchburg G&E	Mass Electric/ Nantucket	Western Mass Electric
Standard Offer/Default Service (cents/kWh)							
12/31/98	3.200	2.800	2.800	2.800	2.800	3.200	2.800
1/1/99	3.690	3.500	3.500	3.100	3.100	3.707	3.100
2/1/99	3.690	3.500	3.500	3.100	3.500	3.707	3.100
4/1/99	3.690	3.500	3.500	3.500	3.500	3.707	3.100
9/1/99	3.690	3.500	3.500	3.500	3.500	3.707	3.100
Transition (cents/kWh)							
12/31/98	3.030	2.730	4.080	3.040	2.820	1.407	3.141
1/1/99	2.760	1.447	3.159	3.040	2.515	1.407	2.836
2/1/99	2.760	1.447	3.159	3.040	1.600	1.407	2.836
3/1/99	2.760	1.447	3.159	3.040	1.600	1.334	2.836
4/1/99	2.760	1.447	3.159	2.100	1.600	1.334	2.836
9/1/99	2.546	1.224	2.998	2.000	1.236	1.182	2.677
Transmission (cents/kWh)							
12/31/98	0.244	1.130	0.372	0.317	0.479	0.384	0.318
1/1/99	0.312	0.312	0.372	0.271	0.479	0.698	0.318
2/1/99	0.312	0.312	0.372	0.191	0.743	0.698	0.318
3/1/99	0.312	0.312	0.372	0.267	0.743	0.698	0.318
4/1/99	0.312	0.312	0.372	0.266	0.743	0.698	0.318
9/1/99	0.312	0.312	0.372	0.291	0.743	0.698	0.318
Distribution ($ per month & cents/kWh)							
12/31/98							
$ per month	$6.43	$6.87	$3.73	$1.34	$2.84	$5.81	$8.49
cents/kWh	3.900	2.211	4.363	3.556	4.402	2.502	2.958
1/1/99							
$ per month	$6.43	$6.87	$3.73	$1.34	$2.84	$5.81	$8.49
cents/kWh	3.900	2.211	4.363	3.556	4.402	2.502	2.958
2/1/99							
$ per month	$6.43	$6.87	$3.73	$1.34	$2.79	$5.81	$8.49
cents/kWh	3.900	2.211	4.363	3.556	4.810	2.502	2.958
9/1/99							
$ per month	$6.43	$6.74	$3.65	$1.34	$2.79	$5.81	$8.33
cents/kWh	3.900	2.434	4.517	3.556	4.810	2.502	2.936
Energy Efficiency (cents/kWh)							
12/31/98	0.330	0.330	0.330	0.330	0.330	0.330	0.330
1/1/99	0.310	0.310	0.310	0.310	0.310	0.310	0.310
Renewable (cents/kWh)							
12/31/98	0.075	0.075	0.075	0.075	0.075	0.075	0.075
1/1/99	0.100	0.100	0.100	0.100	0.100	0.100	0.100

Source: Distribution Company Filings

Transition charges decreased for all companies.

The data show that all LDCs had decreases in the transition charge on September 1, 1999 due to the mandated fifteen percent rate cut. Because of the rate cap, standard offer increases are usually accompanied by transition charge decreases. However, for three reasons, the charges usually will not be the same from company to company. First, LDCs are allowed annual inflation-related increases in rates. Second, LDCs have different rate structures and are permitted to apply the mandated rate discounts on a rate class basis. Third, there may be extraordinary changes in rate components that alter this inverse relationship between standard offer and transition charges.

Transmission rates did not decline and for some companies rates increased.

Through 1999, transmission charges did not change with the major exceptions of Fitchburg Gas & Electric and Massachusetts Electric/Nantucket Electric, who increased their rates. Transmission charges include costs incurred by the LDCs for local transmission (for companies that have local transmission networks) and charges paid by the LDC to the Independent System Operator of New England (ISO-NE), the wholesale electricity power grid operator. These payments can and do change frequently, but LDCs generally file annual changes to transmission rates in conjunction with their reconciliation (true-up) filings. Changes in transmission rates are generally due to changing congestion levels or constraints on the transmission system that impact prices charged by ISO-NE. Changes can also occur when the LDCs' own transmission costs change.

Distribution rates remained unchanged.

The final component of the rates that differs among the various LDCs is the distribution rate.[16] Distribution rates feature two components: a fixed dollar-per-month charge and a variable charge based on usage (per kWh). Generally speaking, during 1999, there was little change in rates for local distribution of electricity, especially in the fixed portion. Four companies featured no change in their distribution rates during the year.

Mandated rate adjustments occurred before the September 1st deadline.

The comparison of pre-September 1999 rates to September 1, 1999 rates shows little change. The total fixed and variable components are shown separately below in Table 8. With few exceptions, the mandated rate adjustments are made in the variable component. Table 8 also shows the disparity in rates among the LDCs, the various rate changes, and how different LDCs complied with the mandated rate reductions. The data also show that despite the September 1, 1999 deadline for the mandated fifteen percent rate reduction, companies were already providing this discount earlier in the year. This further supports the conservative nature of the savings estimates provided in Table 4.

[16] As shown in Table 7, the renewables and energy-efficiency charges changed in 1999; their sum increased by $0.005 per kWh. Such an increase reduces the amount by which LDCs can raise other rate components and still maintain the mandated rate reduction.

Table 8: Residential Customer R-1 Rate Structures, 1999

	Boston Ediston	Cambridge Electric	Comm Electric	Eastern Edison	Fitchburg G&E	Mass Electric/ Nantucket	Western Mass Electric
Total Fixed and Variable Rate Components ($ per month & cents/kWh)							
12/31/98							
$ per month	$6.43	$6.87	$3.73	$1.34	$2.84	$5.81	$8.49
cents/kWh	10.779	9.456	12.02	10.118	10.906	7.898	9.622
1/1/99							
$ per month	$6.43	$6.87	$3.73	$1.34	$2.84	$5.81	$8.49
cents/kWh	11.072	8.878	11.804	10.377	10.906	8.724	9.622
2/1/99							
$ per month	$6.43	$6.87	$3.73	$1.34	$2.79	$5.81	$8.49
cents/kWh	11.072	8.878	11.804	10.297	11.063	8.724	9.622
3/1/99							
$ per month	$6.43	$6.87	$3.73	$1.34	$2.79	$5.81	$8.49
cents/kWh	11.072	8.878	11.804	10.373	11.063	8.651	9.622
4/1/99							
$ per month	$6.43	$6.87	$3.73	$1.34	$2.79	$5.81	$8.49
cents/kWh	11.072	8.878	11.804	9.832	11.063	8.651	9.622
9/1/99							
$ per month	$6.43	$6.74	$3.65	$1.34	$2.79	$5.81	$8.33
cents/kWh	10.858	8.878	11.797	9.757	10.699	8.499	9.441

Source: Distribution Company Filings

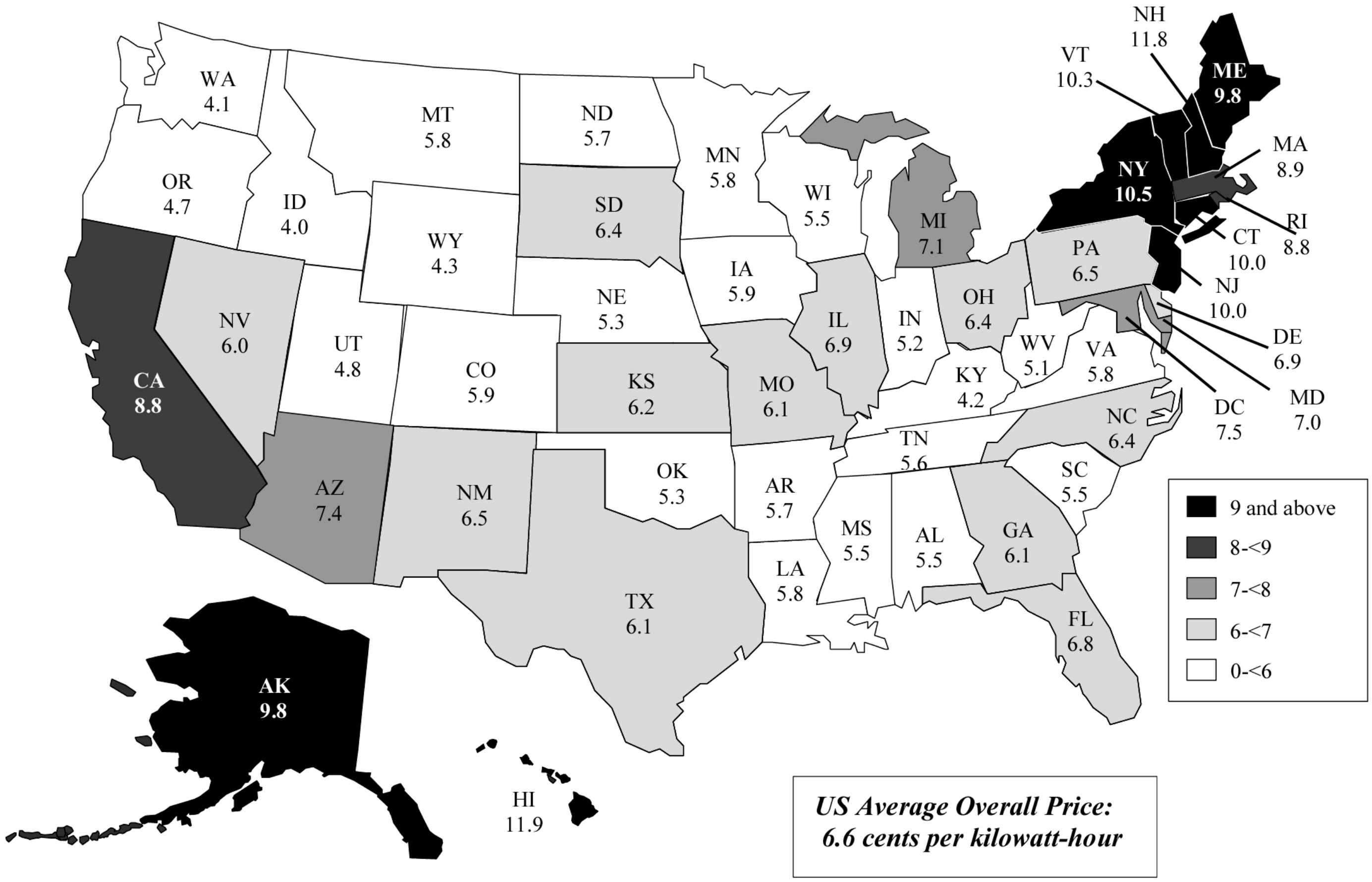
2.6 Electricity Prices: Massachusetts, New England, and the Nation

Massachusetts electricity prices have remained high relative to other states.

The Commonwealth continues to make gains in reducing its electricity prices relative to other states in the nation, but still remains in a group of high-priced states. In 1999, Massachusetts was ranked as having the 9th most expensive electricity prices (8.9 cents per kWh). That is the same ranking as was reported for 1998. In 1997, Massachusetts had the 5th highest average electricity prices.

Figure 3 shows 1999 price data for each state. The prices shown are the weighted-average of prices paid by all customers in each state. The U.S. average electricity price is 6.6 cents per kWh. However, the United States continues to have widely disparate electricity prices among the states with a low of 4.0 cents per kWh (Idaho) and a high of 11.9 cents per kWh (Hawaii). This disparity is reflective of wide differences in supply and demand conditions across the nation.

Figure 3: 1999 Average Overall Electricity Prices by State (cents/kWh)



Source: Electric Power Annual 1999, Volume 1

An examination of Figure 3 shows a cluster of states with prices above 8.0 cents per kWh. Outside of California, Alaska, and Hawaii, all of these states are located in the northeastern United States. The difference between the lowest price state in this group (Rhode Island at 8.8 cents per kWh) and the next region (the District of Columbia at 7.5 cents per kWh) is a large 1.3 cents per kWh. Due to a variety of factors (see the 1998 Market Monitor), Massachusetts continues to be a high-cost state for electricity despite the gains from restructuring. Nevertheless, the gains from restructuring compared to other states can be seen in Figures 4 and 5. As seen in the figures, Massachusetts continues to make gains relative to the other New England states and the nation as a whole. Only Rhode Island, which started restructuring at about the same time as Massachusetts, has done as well.

Figure 4: Historical Electricity Prices for all Customer Sectors: Massachusetts, New England, and United States

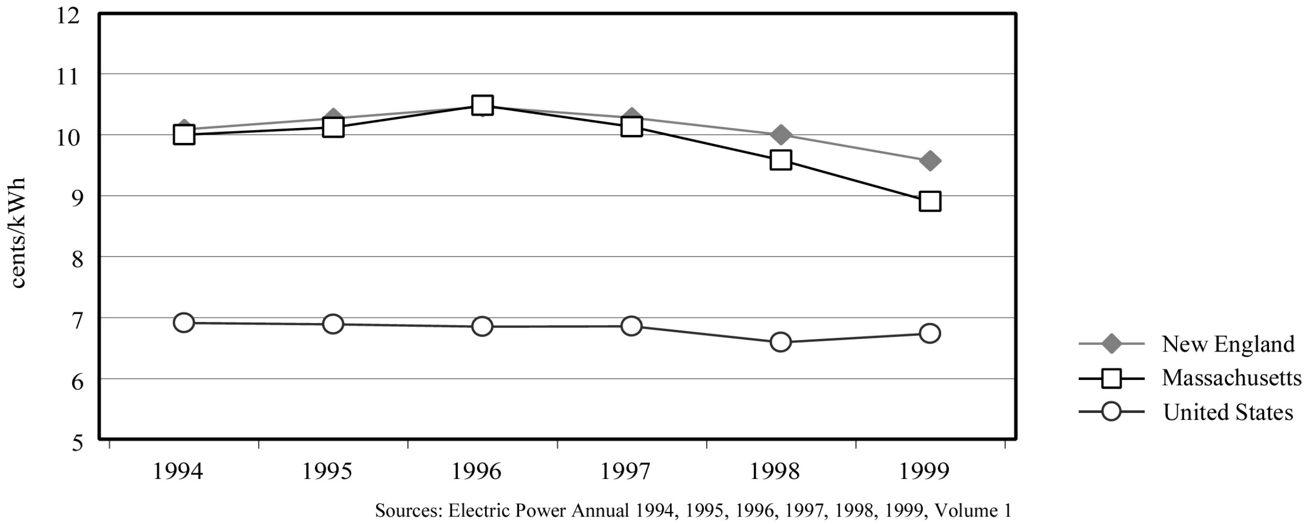
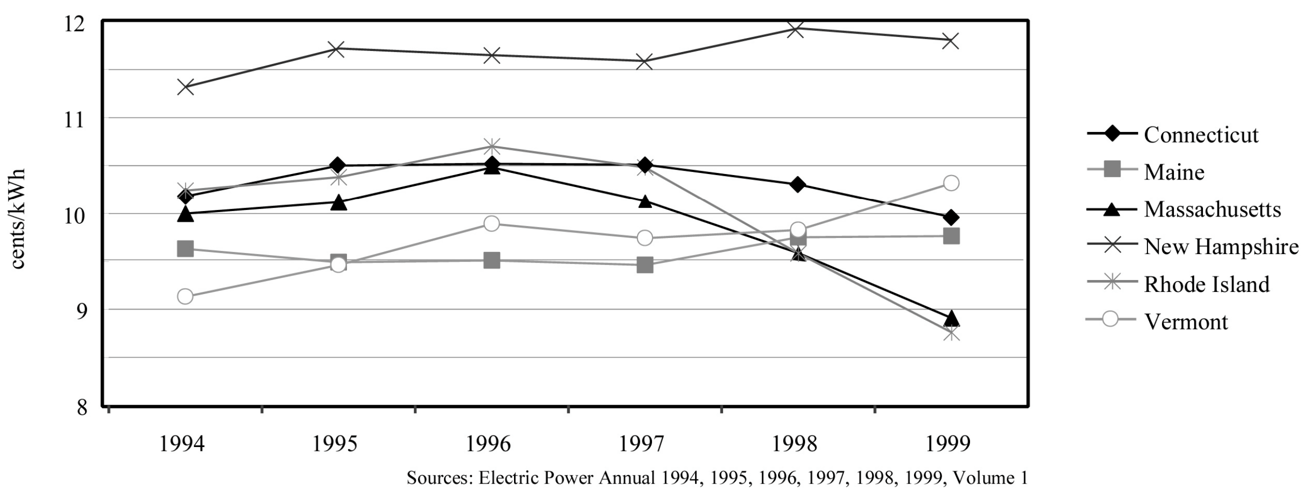


Figure 5: Historical Electricity Prices for all Customer Sectors: New England States



2.7 Prices by Customer Sector: Massachusetts, New England, and the Nation

Industrial customers have enjoyed larger percentage reductions in price than other sectors.

Table 9 illustrates electricity price changes in percent from 1998 to 1999 for three customer sectors (residential, commercial and industrial) for each New England state and the U.S. average. The commercial and industrial customers have enjoyed larger percentage reductions in price than residential customers, with industrial customers receiving the highest reductions. This is highlighted in both Massachusetts and Rhode Island. The other New England states, which restructured later or did not restructure through the end of 1999, feature different reductions. The "All Sectors" column shows the larger relative gains made by Massachusetts and Rhode Island.

Table 9: 1999 New England Electricity Prices (cents/kWh) by Customer Class and Percent Change from 1998 Prices

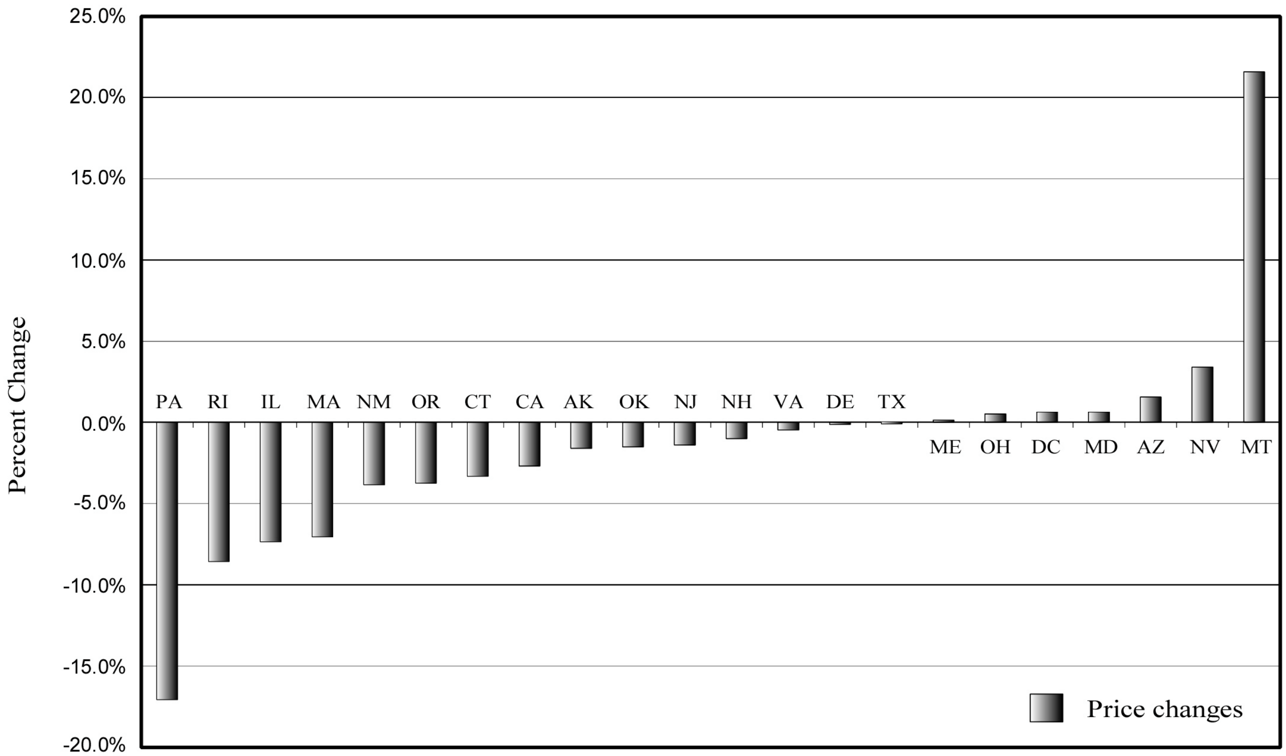
	All Sectors		Residential		Commercial		Industrial	
	1999 Price	Change	1999 Price	Change	1999 Price	Change	1999 Price	Change
Connecticut	10.0	-2.91%	11.5	-3.36%	9.7	-3.00%	7.4	-3.90%
Maine	9.8	0.00%	13.1	0.77%	10.5	1.94%	6.4	-3.03%
Massachusetts	8.9	-7.29%	10.1	-4.72%	8.6	-8.51%	7.4	-9.76%
New Hampshire	11.8	-0.84%	13.9	0.00%	11.4	-1.72%	9.3	-1.06%
Rhode Island	8.8	-8.33%	10.2	-6.42%	8.3	-10.75%	6.7	-11.84%
Vermont	10.3	5.10%	12.2	5.17%	10.7	5.94%	7.3	0.00%
U.S. Average	6.6	-2.08%	8.14	-1.45%	7.18	-3.10%	4.4	-1.79%

Source: Electric Power Annual 1999, Volume 1

2.8 Prices in Deregulated States

As mentioned in the 1998 Market Monitor, this report and subsequent reports will continue to compare the performance of Massachusetts' restructuring efforts, as measured by overall changes in average yearly prices compared to other restructured states. For 1998, Massachusetts showed the largest percent reduction, primarily due to the 10 percent rate cut that occurred in March of 1998. Figure 6 shows the 1999 percentage changes from 1998. For 1999, Massachusetts featured the 4th highest percent reduction among deregulated states.

Figure 6: Price Changes in Deregulated States
From 1998 to 1999



Source: Electric Power Annual 1999, Volume 1

Conclusion

Since the restructuring of electric utilities in the Commonwealth, ratepayers in all service territories have benefited from substantial savings. The $910 million in savings have come predominantly from the rate reductions required by the Act. However, Massachusetts continues to have high electricity prices relative to the rest of the United States. These high prices offer opportunity for competitive market forces to further drive prices down. In the next chapter, DOER examines the activity in retail markets and its effect on customer migration. Competitive markets did not fully mature in 1999, although suppliers have slowly begun to attract a handful of Massachusetts customers.

CHAPTER III: COMPETITIVE RETAIL MARKET DEVELOPMENT

This chapter describes movement in retail markets during the second year of restructuring. While progress was made, several flaws emerged in the retail market. Throughout the year, appropriate parties and authorities either implemented corrective actions or began discussions on remedies.

Overall, competitive retail market development in 1999 was very slow. Two major factors contributing to this were low retail standard offer and default service prices compared to wholesale energy prices and the uncertainty and structural flaws in the wholesale market.

3.1 Retail Market Overview

As shown in Table 10, the retail electric industry accounted for over $4.54 billion in revenue in 1999. Revenue figures are slightly lower than the 1998 number of $4.62 billion reflecting the mandated rate reductions. As reported in the previous chapter, overall rates fell by an average of six percent in 1999. In spite of the fact that sales (measured in GWh) increased by nearly five percent over 1998 levels, companies' revenue decreased.

Table 10: Composition of Massachusetts Retail Electricity Market, 1999

Distribution Company	Number of Customers (Yearly Average)	Electric Revenue* ($ Millions)	Customer Sales (GWh)
Boston Edison	680,818	$1,413.8	14,049.6
Cambridge Electric	45,862	$105.0	1,384.4
Commonwealth Electric	329,329	$395.8	3,758.0
Eastern Edison	195,760	$243.9	2,827.2
Fitchburg Gas & Electric	25,878	$52.1	502.6
Massachusetts Electric	981,469	$1,346.7	17,207.7
Nantucket Electric	10,298	$12.9	109.4
Western Massachusetts Electric	197,996	$358.4	3,885.4
Total: Distribution Companies	2,467,410	$3928.7	43,724.4
Total: Municipal Companies	367,423	$610.4	6,751.3
TOTAL OF ENTIRE STATE	2,834,833	$4,539.1	50,475.7

Sources: FERC Form 1, EIA 826, Municipal Reports to DTE
*These figures represent total electric revenues from sales to consumers

3.2 Customer Migration

Customer migration data indicate that the retail competitive market is developing very slowly. Table 11 shows the statewide numbers of distribution companies' customers on standard offer, default service and competitive service in April 1999 and December 1999.[17] (Company specific numbers are in Appendix A). Table 12 displays the sales of electricity (in kWh) to sectors of customers and the state total. Figure 7 presents a graphic representation of LDC electricity sales in December.

The percent of customers taking standard offer service decreased from 86 percent to 80 percent of all customers.

In total, there were approximately 2,452,431 electric customers in April and 2,456,639 in December.[18] Of the total number of customers in April, 86.6 percent were on standard offer, 13.2 percent on default service and 0.2 percent on competitive service. By December, the number of customers on standard offer decreased by 6.8 percent to comprise 80.5 percent of total customers.

Default service customers as a percent of all customers increased from 13 percent to 19 percent.

More than 469,000 customers were receiving default service in Massachusetts at the end of 1999. Over the April through December timeframe, the number of default service customers compared to the total number of customers increased from 13.2 percent to 19.0 percent. Comparing the number of default service customers in April to the number in December shows a 45 percent increase in the number of customers in the default service category. [19]

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[17] All data were collected by DOER from investor-owned distribution companies who reported data by their respective rate classes. Each company reported two data elements each for standard offer, default and competitive generation service: 1) the number of customers on the last day of the month and 2) the kilowatt-hours (kWh) used during the entire month. Data for residential, farm, and street light rate classes are shown as reported by the distribution companies. The remaining rate-class data were aggregated by DOER as follows: small commercial and industrial (C&I) includes rate classes with average monthly usage levels below or equal to 3,000 kWh/month; medium C&I includes rate classes with average monthly usage levels greater than 3,000 kWh/month but less than or equal to 120,000kWh/month; large C&I includes rate classes with average monthly usage levels greater than 120,000 kWh/month. DOER chose this particular aggregation scheme to simplify the reported data.

[18] The increase in the total number of customers is only about 0.2 percent.

[19] The Act required distribution companies to provide default generation service to customers who "for any reason" stopped receiving generation service from a competitive supplier or had moved into a distribution service territory after March 1998. This switch could occur for a number of reasons: (1) residents of businesses change service territory; (2) suppliers close business operations, leaving customers without a supplier; or, (3) competitive suppliers shift customers to default service when market prices are higher than default service. Thus, in concept, default service was intended to be a transitional service for customers "between suppliers" in the competitive market.

Table 11: Distribution Company Customers, April and December 1999

	NUMBER OF CUSTOMERS							
	Standard Offer		Default		Competitive		TOTALS	
	Apr-99	Dec-99	Apr-99	Dec-99	Apr-99	Dec-99	Apr-99	Dec-99
Residential	1,741,262	1,615,320	284,687	412,593	1,277	1,911	2,027,226	2,029,824
Low Income	122,580	120,800	2,949	3,499	1	1	125,530	124,300
Small C&I	196,883	182,526	29,521	44,180	2,647	3,962	229,051	230,668
Medium C&I	44,903	41,214	4,845	7,179	868	1,657	50,616	50,050
Large C&I	4,356	4,201	428	697	387	652	5,171	5,550
Farms	702	676	15	25	0	0	717	701
Street Lights	13,001	13,682	696	1,038	423	826	14,120	15,546
Total	2,123,687	1,978,419	323,141	469,211	5,603	9,009	2,452,431	2,456,639

Source: DOER Form 110

Less than one percent of total customers switched to a competitive supplier.

Comparing the number of competitive market customers to total customers shows an increase from 0.2 percent to a miniscule 0.3 percent. The total number of customers receiving electric service from competitive suppliers in April was 5,603 customers and in December the number was 9,009 customers. These numbers indicate that the competitive market has not yet reached a high level of customer acceptance.

3.3 Competitive Supplier Activity

The number of licensed suppliers increased, but active marketing decreased.

The MA DTE issued ten additional licenses to competitive suppliers and brokers in 1999 raising to 32 the number of licensed companies. This number was deceiving as an indicator of market development because several suppliers either did not offer products (11 companies) or suspended active marketing in the state. Low supplier market participation rates resulted in few new energy products. Consumers were offered other non-energy benefits such as the convenience of a combined billing service for electricity and other products, or a bundle of combined services including electricity from one supplier.

Table 12: Distribution Company Electricity, April and December 1999

	SALES OF kWh							
	Standard Offer		Default		Competitive		TOTALS	
	Apr-99	Dec-99	Apr-99	Dec-99	Apr-99	Dec-99	Apr-99	Dec-99
Residential	902,036,514	986,582,354	106,606,921	185,446,263	1,007,913	2,107,053	1,009,651,348	1,174,135,670
Low Income	53,647,530	58,730,045	1,271,294	1,903,605	0	1,517	54,918,824	60,635,167
Small C&I	242,314,905	242,949,663	28,236,095	48,453,663	3,123,854	5,778,513	273,674,854	297,181,839
Medium C&I	503,046,980	471,984,420	39,106,543	63,280,238	14,279,419	28,673,311	556,432,942	563,937,969
Large C&I	1,066,617,484	975,750,903	50,186,558	96,190,486	118,177,756	279,812,854	1,234,981,798	1,351,754,243
Farms	1,605,455	1,345,453	13,714	202,547	0	0	1,619,169	1,548,000
Street Lights	23,319,426	29,020,445	751,068	1,010,386	2,042,771	5,756,978	26,113,265	35,787,809
Total	2,792,588,294	2,766,363,283	226,172,193	396,487,188	138,631,713	322,130,226	3,157,392,200	3,484,980,697

Source: DOER Form 110

Standard offer and default service prices were difficult but not impossible to beat.

Although the generation portion of customers' bills increased over 1998 rates, and thus became more competitive with market rates, retail competitive suppliers could barely compete with the standard offer and default service prices. Suppliers seeking to acquire retail customers must purchase power on the wholesale market and incur costs to identify, market, enroll, service, and retain customers as well as offer customers a discount off of standard offer and default service prices or provide some kind of incentive to switch. Average "spot" prices in the wholesale market for electricity were often higher than standard offer and default service rates. As a result, it appeared that retail suppliers and marketers were reluctant to sell power at a loss in hopes of gaining early market share. However, some bundled electricity service with other services as an incentive to switch, but many concentrated their marketing efforts on other deregulated states until the standard offer/default service pricing situation improves in Massachusetts.

Major migration was confined to large commercial and industrial customers.

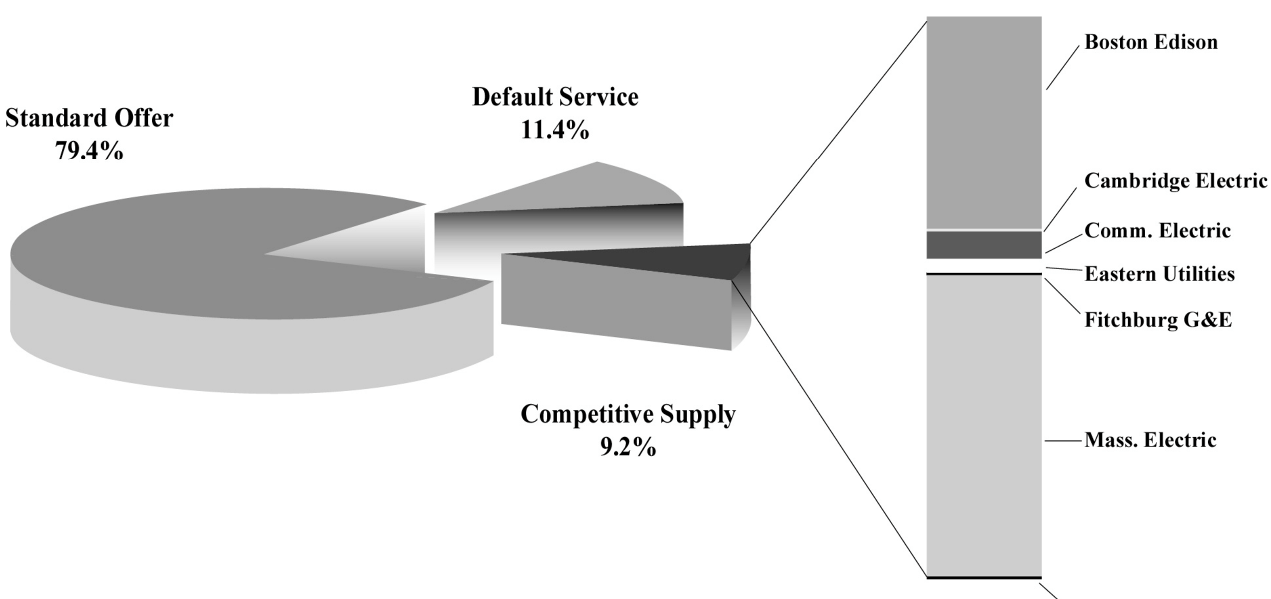
An examination of the competitive generation customers and competitive generation usage in Tables 10 and 11 shows that in terms of electricity usage the large commercial and large industrial customers were the customers that switched to competitive suppliers. Mostly these were high volume, high load factor customers. The large customers that switched also tended to have higher electricity usage than the average usage in their class. For instance, the large commercial and industrial customer who entered the competitive market used on average

429,161 kWh in December as compared to the standard offer and default service large C&I who used on average 232,266 kWh and 138,006, respectively. In terms of competitive market kilowatt-hour sales in December 1999, the large C&I customers used 86.9 percent of total competitive market sales.

Relatively few residential and small business customers switched power suppliers.

The number of residential customers who switched to a competitive supplier and the amount of electricity purchased by them through competitive suppliers were almost non-existent in 1999. By December, 1,912 residential customers out of a total of 2,154,124 residential customers (residential plus discount rate customers) competitively bought 0.17 percent (less than 1 percent) of the total residential load. The low volume of switching implies it was not profitable for many competitive suppliers to pursue standard offer and default service customers receiving a generation price that was well below prevailing market prices.[20]

Figure 7: Composition of Distribution Company Sales: December 1999



Source: DOER Form 110

[20] Most of these "residential" customers opting for competitive supply were in Boston Edison and Mass. Electric's service territory. Boston Edison's tariff for Residential - No Space Heating customers includes hotels and apartment buildings of less than ten units. Most other companies' tariffs for Residential – No Space Heating are for single private dwellings or an individual apartment or residential condominium.

3.4 Responses to Default Service Growth

DTE opened a default service price docket (DTE 99-60).

In 1999, a couple of factors warranted the DTE's investigation of whether or not default service pricing should be changed.

First, the number of customers on default service was growing. As previously mentioned, by December 1999 more than 469,000 customers were receiving default service in Massachusetts. In the absence of a fully developed market during the first year of restructuring, the DTE had directed distribution companies to use their standard offer service price as a proxy for the market price of electricity and thus as the basis for their default service price. One of the problems with a large pool of default service customers is that utilities can recover, at a later date, the above-market costs to serve these customers, plus interest when they buy power to supply them. Under certain circumstances, the potential amount of these "deferred losses" can be substantial. (All customers, rather than just default service customers, pay for deferred losses through the distribution charge.) Also, some believed that default service pricing needed to be changed to reflect market forces and encourage customers to move into the competitive market.

Second, ISO-NE opened wholesale markets to competitive bidding in May 1999. With the opening of the wholesale markets, more market information was available that could be used in setting the default service rate and therefore the time was appropriate to begin an investigation. The Act required the DTE to set rates for default service, and states that those rates should "not exceed the average monthly market price for electricity."

In addition, several retail suppliers indicated that they were ready, under certain conditions, to offer all classes of customers, including residential customers, competitively priced alternatives to standard offer service. Many suppliers believed it was time to move to market pricing for default service. They contended that since most distribution companies had divested their generation assets, the costs distribution companies incur to purchase and deliver power supplies to default service customers should be reflected in the generation charge rather than the distribution charge.

In June 1999, the DTE opened a generic proceeding into the pricing and procurement of default service (DTE 99-60). In its rules implementing the Act, the DTE reiterated that the rate for default service not exceed the "average monthly market price for electricity." However, the DTE's rules are silent on the issue of how the average monthly market price for electricity is determined and on other aspects of default service. Although the DTE's primary objective for the proceeding was to gather information to determine how the "average monthly market price" should be incorporated in the default service rate, the DTE also wanted to know about the implications of various proposals on the competitiveness of the retail market. Through July 1999, the DTE accepted comments on several questions. By the end of 1999, the DTE had not issued a decision.

3.5 Other Market Developments

Utility mergers changed the landscape of retail markets.

Electric utility mergers were one of the most significant events in 1999 that reshaped the retail electric industry and introduced new owners from outside of New England. Formerly vertically integrated electric companies, having sold off their generation, developed into companies primarily focused on the delivery of electricity and other services. (In 1998 there was a rush by out-of-state companies to buy New England's electric generation assets.) These distribution companies are seeking partners to expand and build themselves into larger, regional companies. Some of the reasoning behind the mergers is that it is the only way now for the companies to lower costs, eliminate duplicative operations, and create economies of scale. Therefore, through mergers and consolidations, companies should save money and be able to pass along those savings to consumers. Companies such as New England Electric System (NEES) will finance initial mergers, in part, with cash they received from the sale of their generating assets in 1998. [21]

BEC Energy/Commonwealth Energy (NSTAR) – electric and natural gas distribution companies combination.

NSTAR, a new public utility holding company, was created through the merger of two existing holding companies, BEC Energy and Commonwealth Energy System. The merger was first announced in December 1998 and after receiving all regulatory approvals was finalized on August 25, 1999. NSTAR's utility subsidiaries are Boston Edison Company, Commonwealth Electric Company, Cambridge Light Company, Canal Electric Company and Commonwealth Gas Company.[22] Through this merger, NSTAR will concentrate its activities in the transmission and distribution of energy (electric and gas). The new combined energy delivery company serves approximately 1 million electric customers in 81 communities and 240,000 natural gas customers in 51 communities in Massachusetts. NSTAR's goal is to reach 2 million customers by the end of year 2000. The cost savings from the merger are expected to be about $633 million during the ten-year period 2000-2009. The savings will come from efficiencies of scale, the elimination of management positions and duplicative programs, and energy sourcing[23].

Although the holding companies' union did not need the MA DTE's approval, the companies did need the DTE's approval for the their consolidated rate plan (DTE 99-19). (If the rate plan was not approved, the companies had stated that they would not proceed with the

[21] In Massachusetts, the DTE oversees some aspects of utility mergers such as new rates. The DTE merger guidelines call for the agency to decide in a merger proceeding if there is "no net harm" to ratepayers. In other words, customers must be no worse off than they would have been if the merger had not occurred.

[22] The holding companies proposed to consolidate many of the operations of Boston Edison, Cambridge Electric, ComElectric and ComGas, but the corporate existence of these distribution companies will continue after the merger of BEC Energy and ComEnergy System.

[23] According to the companies, because of the electric distribution companies' different load and peaking profiles, the combination of Boston Edison, Cambridge Electric, and ComElectric into one system entity will result in avoided capacity costs associated with the solicitation and procurement of standard offer and default service of $7.1 million over the 2000-2009 period.

merger.) After regulatory hearings, the DTE approved a rate plan in July 1999. The DTE determined that the costs from the merger will be offset by savings from the merger.[24]

An important aspect of the approved rate plan was that the distribution rates for Boston Edison, Cambridge Electric, ComElectric, and ComGas' will not be raised for four years following consummation of the merger unless allowed exogenous[25] factors result in cost changes.[26] In addition, rate structures remained separate. Thus, any potential scale economies were not reflected in a lower overall rate for customers of the new merged company. (The distribution charge portion of the retail bills is about 40 percent of the total bill.) The DTE did require that any individual exogenous cost must exceed a threshold in order to qualify for recovery.[27]

The approved plan also included a Service Quality Plan.[28] For the electric companies, the plan has measures for four performance areas: system reliability, customer service, safety and billing with performance benchmarks for each measure. For the gas company the three performance areas are: customer service, safety, and billing. The purpose of the benchmarks is to represent the level of pre-merger performance that the companies are expected to maintain (or exceed) during the post-merger period. The companies were also required to file with the DTE penalty mechanisms in order to motivate the companies to meet or exceed the established benchmarks.

National Grid/NEES – first foreign ownership of a U.S. utility company

In December 1998, the New England Electric System (NEES) announced it would merge with National Grid Group. National Grid is the world's largest independent electricity transmission company. Headquartered in England, the company owns and operates a high voltage transmission network, including interconnections in Scotland and France. National Grid has experience in running a transmission grid in England's competitive electric market. NEES, based in Westboro, MA, is a public utility holding company serves approximately 1.3 million customers through its subsidiaries Massachusetts Electric Company (MA), Narragansett Electric Company (RI), Granite State Electric Company (NH), and Nantucket Electric Company (MA). Having sold off most of its generation assets in 1998, NEES has focused on expanding its energy delivery services.

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[24] However, a group of four intervenors and the MA Attorney General filed two separate appeals on the DTE's rate plan order with the Massachusetts Supreme Judicial Court (SJC) in August 1999. The appeals were still pending at the end of 1999.

[25] Exogenous costs include changes in tax laws, accounting principles, regulatory, judicial or legislative requirements.

[26] Some petitioners wanted the DTE to order the companies to incorporate performance measures in the rate plan (PBR). However, the DTE said in DTE 99-19 that while the Act authorizes the Department to implement PBR, the PBR regulatory scheme is not mandatory. St. 1997, c. 164 § 193; G.L. c.164 §1E. The Joint Petitioners have not proposed a PBR, but a Rate Plan that incorporates a four-year rate freeze; it is not a traditional general rate case.

[27] The DTE determined that any individual exogenous cost must exceed the threshold amounts of $2,400,000 for Boston Edison, $175,000 for Cambridge Electric, $625,000 for ComElectric, and $425,000 for ComGas in a particular year for the companies to request recovery of exogenous costs.

[28] DTE has stated that the quality of service is an essential factor in reviewing a merger and that a service quality plan can be an important bulwark against the deterioration of a company's quality of service. DTE has directed "companies filing requests for approval of mergers and acquisitions to include a service quality plan that is designed to prevent degradation of service following the merger."

The merger required the approval of several regulatory bodies. These included approvals from the U.S. Department of the Treasury's Committee on Foreign Investment in the U.S., the Securities and Exchange Commission, the Department of Justice, the Nuclear Regulatory Commission, and the Federal Energy Regulatory Commission (FERC) as well as support or approval from the states in which NEES operates. [29]

NEES/EUA – one of the largest electric distribution companies in New England

At about the same time that National Grid was in the process of acquiring NEES, NEES announced in February 1999 that it was seeking to acquire Eastern Utilities Associates. The NEES/EUA merger was not contingent on the NEES/National Grid merger, but the proposal had the full support of National Grid. EUA, a Boston-based public utility holding company whose subsidiaries include Eastern Edison Company, Blackstone Valley Electric Company, and Newport Electric Corporation, serves about 300,000 customers. Upon completion of the merger, EUA's operations would be merged into NEES'. The new combined company will serve 1.6 million electricity customers in 228 New England communities and will serve more electricity customers in both Massachusetts and Rhode Island than any other company. NEES stated that the merger advances their goal of growing their energy delivery business to achieve more efficiencies.

In April 1999, NEES and EUA filed with the DTE a petition for approval of the merger including a rate consolidation plan (DTE 99-47). This filing was one step in a series of regulatory approvals at the federal and state levels needed for the proposed merger.

In November 1999, a Settlement was filed jointly by the DOER, Associated Industries of Massachusetts (AIM), the Massachusetts Attorney General, The Energy Consortium (TEC), Massachusetts Electric Company (MECo), Nantucket Electric Company, Eastern Edison Company, New England Power Company, Montaup Electric Company, NEES, National Grid, and EUA. The settlement was designed to resolve issues before the DTE in the proceeding, DTE 99-47.[30]

Internet-based discount energy suppliers began to emerge.

In 1999 e-commerce, the method of conducting business digitally through the Internet and electronic mail, pervaded almost every sector of the American economy. A recent study conducted by the Forrester Research Group forecasted that, worldwide, 11 percent of all electricity trading and 25 percent of all gas trading will occur electronically by 2004.[31]

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[29] On March 20, 2000 the merger was completed. This merger, the first U.S. acquisition for National Grid, was also one of the first mergers FERC has approved between a foreign owned company and U.S. utility. NEES became a wholly owned subsidiary of National Grid and officially changed the NEES name to National Grid USA. The names of these local electric companies will remain the same and these companies will continue to serve their customers. National Grid USA will continue to identify and pursue new opportunities for investment in mergers and acquisitions involving electricity transmission and distribution systems and development of new transmission projects.

[30] The DTE evaluated the benefits and costs associated with the merger based on 1) the effects on rates, 2) the effects on service quality, 3) societal costs and 4) distribution of resulting costs and benefits between shareholders and ratepayers. Based on these factors, the DTE approved the plan in March 2000.

[31] Forrester Research. *The Surge of Online Energy.* September 1999.

The Massachusetts electricity market was not excluded from e-commerce activity. Several companies became licensed to sell competitive electricity products. These products offered consumers five to ten percent discounts on the generation portion of their electric bills sometimes with a combination of long distance telephone or other services. In many instances, customers stayed on standard offer generation service but received a discount at the end of the year.

If energy wholesalers, retailers, and consumers are to increasingly consider the Internet a viable means for business transactions, several hurdles must be cleared in Massachusetts. Companies must ensure to their customers that their web sites are secure for passing financial information—the relative novelty and anonymity of the Internet has caused consumers to react with caution. Several other deregulated states have permitted electronic transactions making it much easier for consumers to switch to competitive suppliers. However, these states must ensure against the risk of abuse, slamming, and fraud.

As with any emerging market, predictions are difficult to make. While it is certain that energy e-commerce will have a significant role in the next few years, exactly what that role becomes remains a large question mark. However, by eliminating some of the traditional acquisition expenses with strategies such as no paper bills, small call centers, and targeted e-mails, it is conceivable that web-based energy suppliers can more effectively market their products and make a profit. DOER will continue to follow e-commerce activity in 2000 and developments will be addressed in detail in the 2000 Market Monitor.

Conclusion

Lack of significant customer migration and a decrease in competitive suppliers offering products in Massachusetts indicates that there does not yet exist a robust retail market for electricity. Yet the retail industry is only half of the equation—the wholesale market for electric power underwent a significant transformation in 1999, furthering uncertainties across the entire deregulated industry. 1999 demonstrated a disconnect between the wholesale and retail markets in which consumers were effectively sheltered from price signals and thus could not respond in a cost-effective manner. The next chapter explores the significant changes in the wholesale markets in Massachusetts in 1999.

CHAPTER IV: WHOLESALE MARKET DEVELOPMENT

This chapter describes the new system for New England's wholesale electricity market that began on May 1, 1999. On that date, the manner in which electricity is dispatched in the New England grid was changed with the implementation of an hourly energy market and new ancillary services markets. This new market-based system was a radical departure from the historic, regulated energy system in which all electric power generators were dispatched based on their cost. This section also reports on wholesale electricity supply, demand and prices, as well as system reliability. This section highlights market imperfections in 1999 and subsequent market changes to correct market flaws.

4.1 Wholesale Market Administration and Oversight

The Independent System Operator of New England (ISO-NE) is responsible for dispatching electric generators, facilitating financial settlements, operating the transmission system in real-time, and maintaining system reliability. With the introduction of a competitive wholesale market for electric energy in New England, ISO-NE also administers the "products" that were developed to support the market and the reserve requirements. ISO-NE is a non-profit entity, under contract with the New England Power Pool (NEPOOL)[32] to operate the bulk electric power system, manage the wholesale market, and administer the NEPOOL Open Access Transmission Tariff (NOATT). Because it operates an interstate system, ISO-NE is regulated by the Federal Energy Regulatory Commission (FERC).

Not long after ISO-NE was created, some NEPOOL participants questioned whether or not ISO-NE could be truly "independent" if NEPOOL was controlled by vertically integrated utilities. These concerns prompted FERC to order that NEPOOL revise its membership and voting structure. A new governance provision created the Participants Committee to replace the Executive and Management Committees and allocated voting to five sectors: Generation, Transmission, Suppliers/Marketers, Publicly-Owned/Municipal Power, and End Users.[33] Each sector receives 20 percent of the aggregate vote. On July 16, 1999 the new governance structure was approved by the FERC.[34] NEPOOL members vote on each change to the NEPOOL tariff or Market Rules and Procedures.[35]

4.2 Wholesale Market Design

The new wholesale market system was implemented on May 1, 1999.

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[32] NEPOOL is a voluntary association of entities that are engaged in the electric power business in the six New England states. NEPOOL members are referred to as the "Participants."

[33] The End Use Sector had not attained full sector voting status by the end of 1999.

[34] FERC Docket # ER99-1142-005 and ER99-2893

[35] Most analyses and recommendations are prepared by four NEPOOL committees: Transmission Planning, Reliability, Tariffs, and Markets. All recommendations are taken to the Participants Committee, where all NEPOOL members vote on each change to the NEPOOL Tariff or Market Rules and Procedures. New market rules and changes must be approved by a two-thirds majority vote of the Participants. The FERC must authorize any change to the Restated NEPOOL Agreement (RNA), the NEPOOL Open Access Transmission Tariff (NOATT), or the Market Rules. However, the FERC will generally not oppose changes that are approved by the NEPOOL Participants Committee.

May 1, 1999 marked the opening of the new market system. With a market-based rate, electricity sellers were free to offer their energy at prices of their own choosing and assumed the financial risk of doing so. While buyers and sellers continued to contract for energy through long-term, bilateral contracts they could also trade energy on an open "spot" market at market prices. The spot market is an electric power exchange administered by the ISO-NE.

The new wholesale market is based on bid prices rather than regulated cost.

Historically, vertically integrated utilities met their captive load obligations (customer demand) through a combination of their own electric generation facilities and long-term power purchase agreements with merchant generators. Any residual energy demand or supply was bought or sold through the power pool. The power pool operator dispatched the residual energy based on reported fuel costs and reported heat rates for generators ("heat rate" is the measure of how efficiently a generator can convert fuel to electric power). Under this historic system all generation costs were recovered through the regulated tariffs.

This scenario changed after Massachusetts and other states passed restructuring legislation that freed electric generation from regulation and created the foundation for an electricity market. Over the last couple of years, most electric utilities in Massachusetts and other deregulated New England states sold their generating units to merchant generating companies and power marketers. The new wholesale market allowed generators to competitively offer their services into the power pool at a market price.

The market was designed with seven products, one of which was eliminated.

The newly designed wholesale market began with seven market products, but at the end of 1999 NEPOOL petitioned FERC to eliminate one of the markets. The six hourly markets included:

- Energy
- Automatic Generation Control (AGC)
- Ten Minute Spinning Reserves (TMSR)
- Ten Minute Non-Spinning Reserves, (TMNSR)
- Thirty Minute Operating Reserves (TMOR)
- Operable Capability (OpCap)

On December 30, 1999, NEPOOL filed with FERC to eliminate the OpCap market effective March 1, 2000. NEPOOL determined that the OpCap market was redundant with no demonstrable value to consumers.

The Energy (or spot) market is the largest of the markets. It is measured in kilowatt-hours and settled as Adjusted Net Interchange (ANI). ANI is the net of each participant's supply into the system, minus withdrawals. Each generation asset designee must submit a bid price into the market to supply energy. All bids are received and then ranked or stacked by ISO-NE from lowest to highest price. The ISO dispatches each generation asset based on the order of price, unless the generator must be held in reserve for reliability purposes. The last or "marginal" (typically most expensive) generator that the ISO dispatches for energy to meet load demand generally sets the Energy Clearing Price (ECP)[36]. The ECP is what each market participant with negative ANI in the hour pays for energy purchased through the wholesale market.

Only generators that can be controlled directly by ISO-NE can provide the AGC product. AGC is also called "regulation service" and is measured by a generator's ability to increase or decrease output in response to ISO-NE commands. This service is used to keep the proper level of energy on the system in response to small changes in electrical load. ISO-NE also purchases from the market the three reserves products (TMSR, TMNSR, and TMOR) to maintain system reliability by keeping extra generation ready to come on in the event of a partial system failure. The amount of reserves purchased by the system operator is dictated by the Northeast Power Coordinating Council rules, and is dependent upon the largest system contingencies.[37]

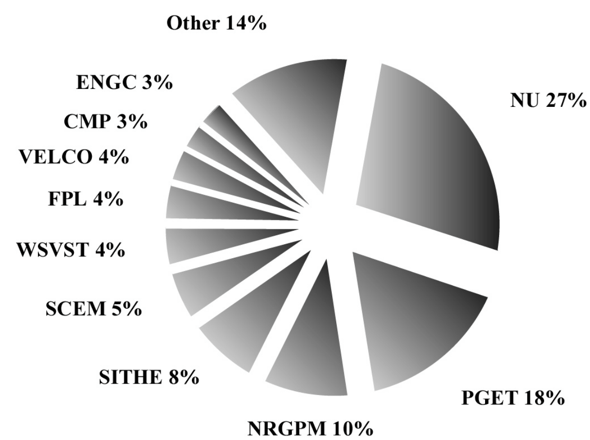
The last of the seven products is the Installed Capacity (ICAP) market. This product was the first sold through ISO-NE when the wholesale market changes began in September 1998. The ICAP market was designed to pay generators for keeping excess generation available in New England. Unlike the other markets, ICAP is a monthly rather than hourly product. Each load serving entity in New England is given an ICAP requirement, based on an Objective Capability target and peak load. Market participants who are deficient in ICAP pay the clearing price for each megawatt month to those participants who had surplus.[38]

4.3 Wholesale Market Electricity Supply and Demand

Generation ownership has changed dramatically.

The ownership of generation has changed dramatically since the inception of electric industry restructuring. Of all the formerly vertically integrated utilities in New England prior to deregulation, only Northeast Utilities (parent company of the Western Massachusetts Electric Company) retained a large generation portfolio, with 27 percent of generation capacity in NEPOOL. Because most utilities sold their generation in whole to single bidders (Figure 8),[39] generation remained highly

Figure 8: 1999 NEPOOL Generation Capacity Ownership



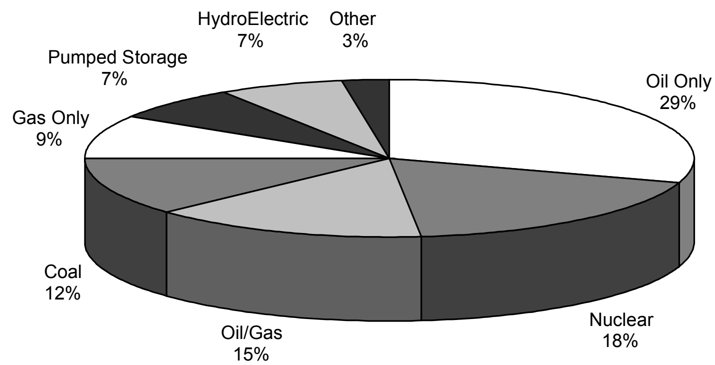
[36] NEPOOL Market Rule 5 specifies when generating units are eligible to set the energy clearing price.
[37] The largest system contingency in 1999 was the Phase II Hydro Quebec interconnection that supplies a large portion of the New England demand - typically around 1500 Megawatts. Contingency planning provides that sufficient generation will be kept in reserve and ready to replace the loss of the largest and second largest contingencies.
[38] There has been considerable controversy with this market product because it is thinly traded and it is difficult to verify to the value of the capacity sold into the market. The NEPOOL Participants Committee voted to have the current ICAP market replaced by another capacity market before the end of 2001.
[39] List of abbreviations: Central Maine Power Co. (CMP), Entergy Nuclear Generation Co. (ENGC), FPL Energy Power Marketing, Inc. (FPL), Northeast Utilities Co. (NU), NRG Power Marketing Inc. (NRGPM), PG&E

concentrated with the three largest generation owners in New England controlling over 50 percent of the generation assets.

New England Electric Generation Capacity and Fuel Mix

The electric generation capacity mix is little unchanged from the previous years, other than the addition of 730 Megawatts of gas and duel fuel (oil and gas) units. The region's top source of generation capacity is still fuel oil[40] (Figure 9).

Figure 9: New England Electric Generation Capacity Mix, 1999



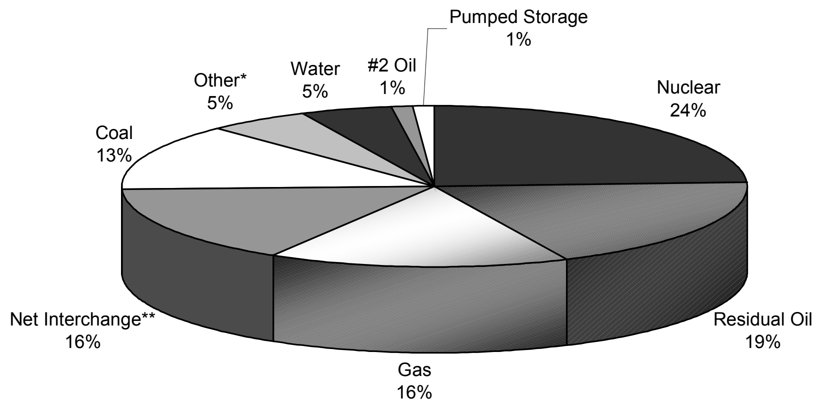
Sources: ISO-New England, EIA

Despite being second in capacity, nuclear was the primary fuel for electric generation in New England in 1999 (Figure 10). This reflects a higher capacity utilization ratio for nuclear assets in New England, which was partially a reflection of the low marginal cost of nuclear power, as well as improvements in operations. Imports served a large portion of New England's energy requirements, which is reflected in a sixteen percent positive net interchange. Interconnections with Hydro Quebec provided nearly half of the net imports into New England in 1999. The "Other" category consists of biomass, refuse, and other non-fossil fuel sources.

Energy Trading L.P. (PGET), Southern Co. Energy Marketing (SCEM), Sithe New England Holdings (SITHE), Vermont Electric Power Co. (VELCO), Wisvest-Connecticut, LLC (VISVEST)

[40] Primarily residual oil, also known as #6 fuel oil.

Figure 10: New England Generation Fuel Mix, 1999

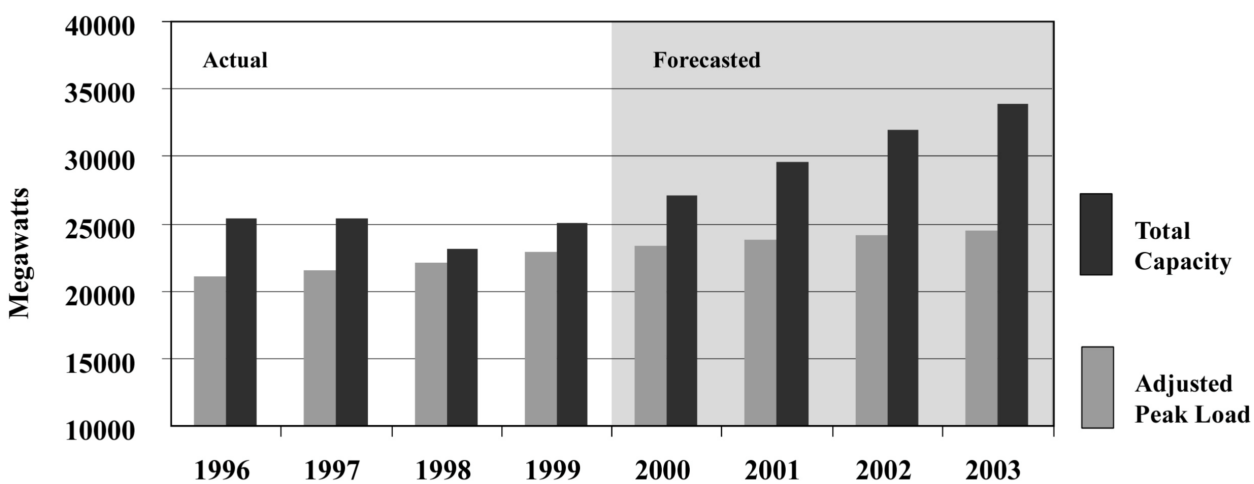


Sources: ISO New England, EIA

Generation capacity expected to keep pace with demand.

Open access to the transmission system and a new source of natural gas supply are two of the factors that are contributing to investment in new generation in New England. This expected increase in capacity should be sufficient to meet demand growth in the coming years. Figure 11 shows the historical trends and forecasted growth in generation capacity relative to peak demand in New England.

Figure 11: New England Total Capacity and Adjusted Peak Load



Source: 2000 NEPOOL CELT Report

New generation capacity for New England in 1999 totaled 730 megawatts.

As demand grows and older power plants are withdrawn, it is essential to continue to develop new generation in the region. In 1999, 730 megawatts of new generation capacity were added in New England. An additional 1,250 megawatts of capacity is expected on-line in 2000 in New England. Table 13 lists the Massachusetts plants recently built, under construction, and planned through 2002.

Table 13: Massachusetts Generation Capacity 1999-2002

Name, Developer	Size	Location	Completed/ Expected
Dighton Power, Calpine	160 MW	Dighton	1999
Berkshire Power, PDC	275 MW	Agawam	2000
Millenium, PG&E	360 MW	Charlton	2000
Blackstone, ANP	580 MW	Blackstone	2001
Bellingham, ANP	520 MW	Bellingham	2002
Mystic Expansion, Sithe	1,600 MW	Everett	2002
Edgar Station Expansion, Sithe	750 MW	Weymouth	2002
Nickel Hill, Constellation	750 MW	Dracut	2003
TOTAL GENERATION	4,995 MW		

Source: ISO-New England, Annual Market Report 1999 - 2000

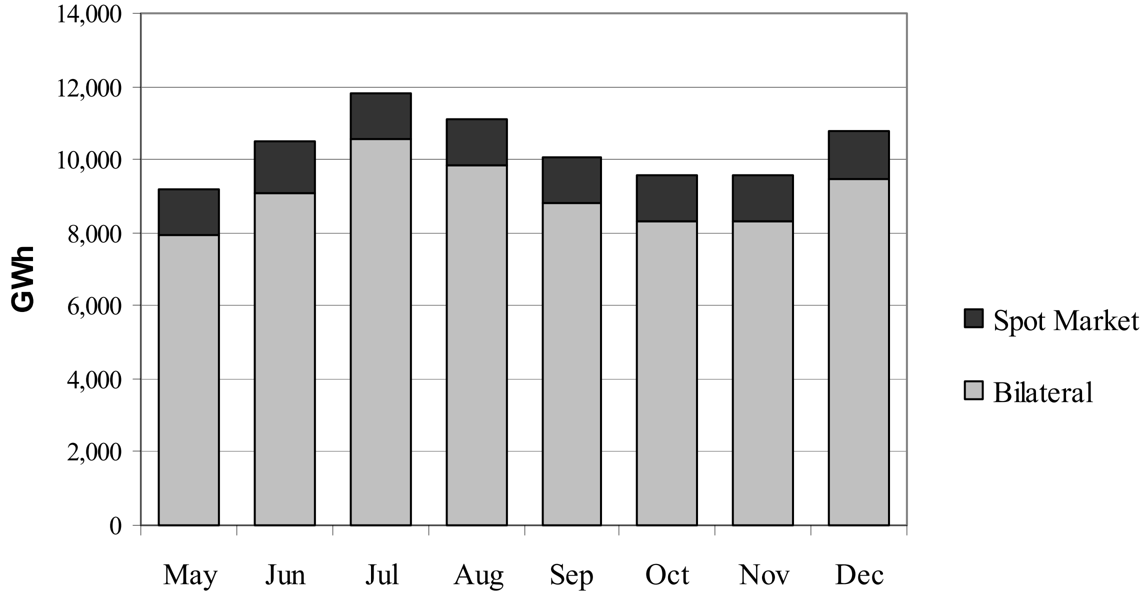
All of the new capacity is expected to use natural gas as its primary fuel. There are several reasons that developers are relying almost exclusively on natural gas as the fuel for electricity generation. Advances in gas turbines have dramatically increased efficiencies and lowered the operating and capital costs of these units. New natural gas pipelines have increased the gas supply into New England. However, the increased reliance on natural gas to generate New England's electricity poses reliability concerns. These concerns will be addressed in the 2000 Market Monitor Report.

4.4 Wholesale Electricity Market Prices

About eight to fifteen percent of daily system load was sold through the spot market

In 1999, most electricity in New England was sold through bilateral agreements, not through the energy or spot market administered by the ISO-NE. The energy sold through the spot market in 1999 represented between eight and fifteen percent of the daily system load. Figure 12 shows the monthly amount (in Gigawatt hours) of energy sold on the wholesale spot market relative to the total system load.

Figure 12: Wholesale Market Volumes, 1999



Source: ISO-New England

By entering bilateral agreements with suppliers and other load serving entities, generators receive a guaranteed price for their output. The real-time or spot market serves the purpose of allowing suppliers to adjust their purchases based on the actual demand for energy. A seller or buyer may choose to sell or buy exclusively on the spot market. However, this strategy has more risk for a buyer who has an inflexible load obligation, as energy prices will be subject to volatility on the spot market. The cost of this risk should be reflected in the difference between the average bilateral price for energy and the average spot price.

In order to evaluate wholesale electricity prices, all related costs should be included. Buyers are responsible for paying for their share of the pool reserve requirements, as sold through the five ancillary services markets described in section 4.2. Additionally, load serving entities must pay for system congestion costs and imbalances caused by generators running out of merit.[41] Generators may be run out-of-merit to supply energy in an area where there is insufficient transmission to import lower-cost power, or when a generator's physical constraints keep the unit running even though its price is no longer "in merit order." These costs, known as "uplift" costs, are paid by all customers to allow generators to recover the difference between the clearing price and their actual bid price for those hours that they ran out of merit.

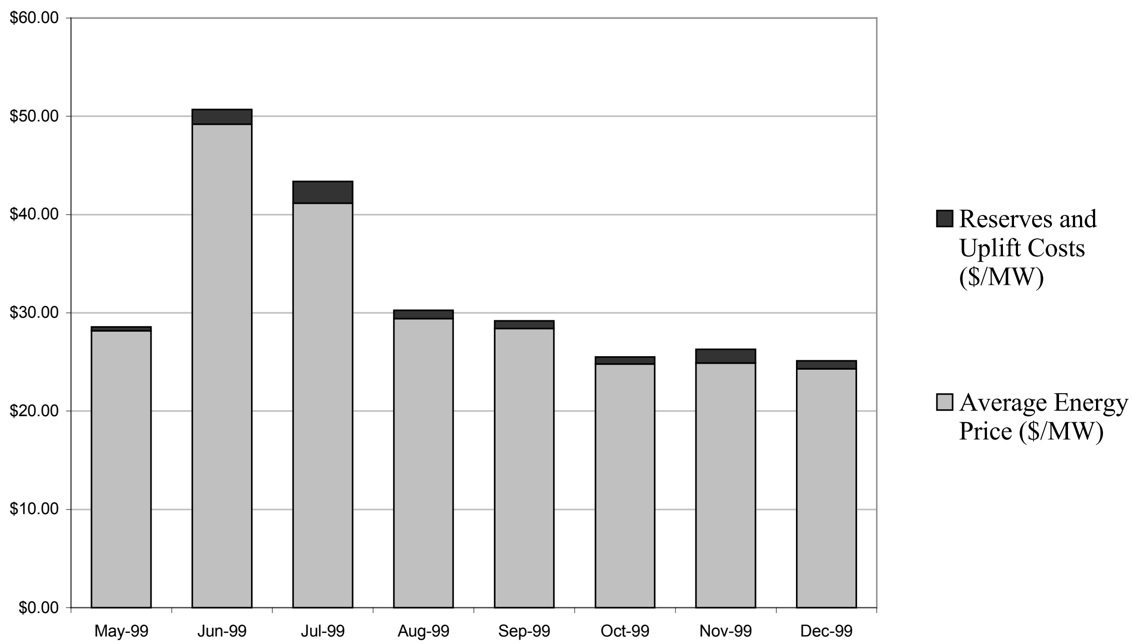
Energy prices are highest during peak demand periods.

Energy is the largest cost component for wholesale electric purchases, as shown in Figure 13. Wholesale energy prices are typically highest during peak system demand. Electricity demand is dynamic, with daily cycles and seasonal peaks. In the absence of significant load

[41] When a generation asset is termed to be running "out-of-merit" it means that it is more expensive than the marginal generator. When a generator is running out of merit it is not eligible to set the Energy Clearing Price.

management, sufficient excess capacity must be available for the peaks. Because some generators will only run on the days with the highest load, they only receive energy revenues a few days per year. However, peaking generators can receive significant additional revenues by selling into the reserves markets.

Figure 13: Monthly Wholesale Market Prices



Source: ISO-New England

In June 1999, when demand on the electric system was high, the weighted average clearing price was its highest at $58.03/megawatt hour. In the unusually mild weather during the month of December 1999, when demand for electricity was less than expected, the weighted average price in New England was $25.05/megawatt hour.

The hourly energy supply curve is near vertical at peak system load.

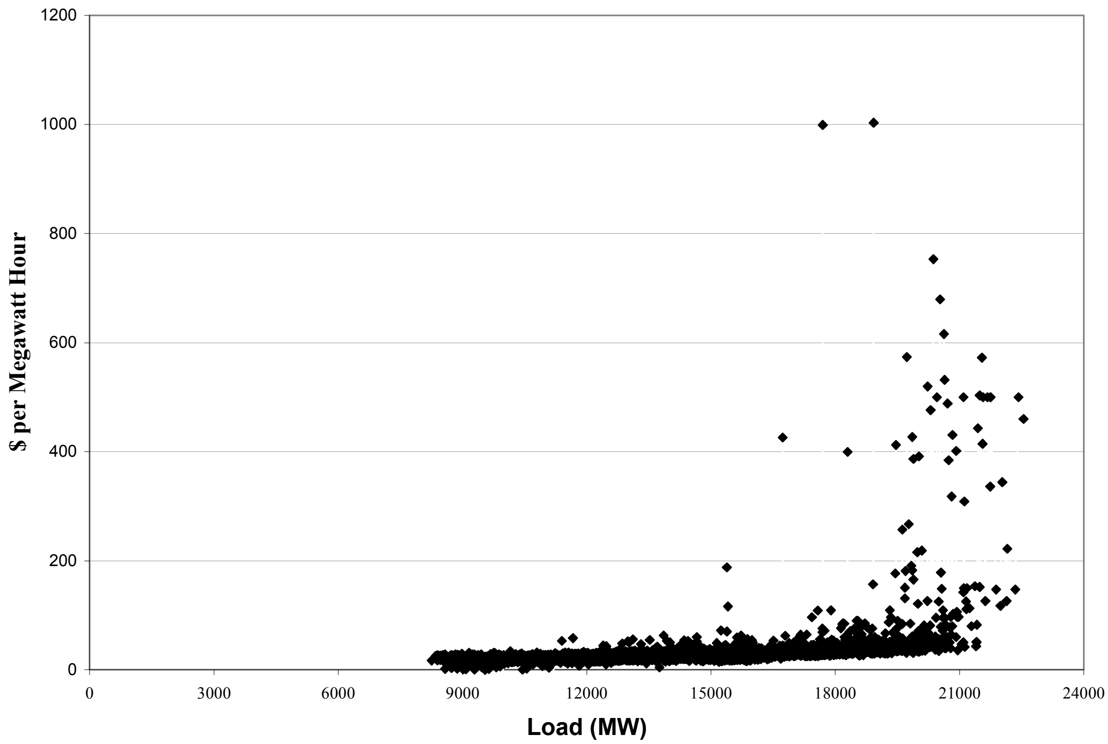
Prior to May 1999 the marginal "price" of wholesale electric energy, called the system lambda[42] was highly correlated to demand and the price of oil. At the start of the competitive wholesale market, that relationship has been broken. Under a market system, there is no longer a price determined by a regulated formula or tariff. Rather, a volatile wholesale market will increase the price risk premium for supplying retail energy. On June 6, 1999 unexpectedly high demand drove the wholesale market price to $1003 per megawatt for one hour, and for several hours the prices were well above historical highs.

When demand reaches the limit of capacity, the price for power becomes very expensive, since the most expensive generation must be run. Also, the holders of remaining capacity

[42] Lambda is a term commonly given to the incremental cost that solves the least-cost economic dispatch calculation. It represents the cost of the next megawatt that could be produced from units in the system in order to provide enough power to meet the hourly demand.

have no incentive to keep bids low because of limited competition to supply the next kilowatt. As shown in Figure 14, the hourly energy supply curve is near vertical when system load is near its peak.

Figure 14: Wholesale Electricity Price Relative to Load, 1999

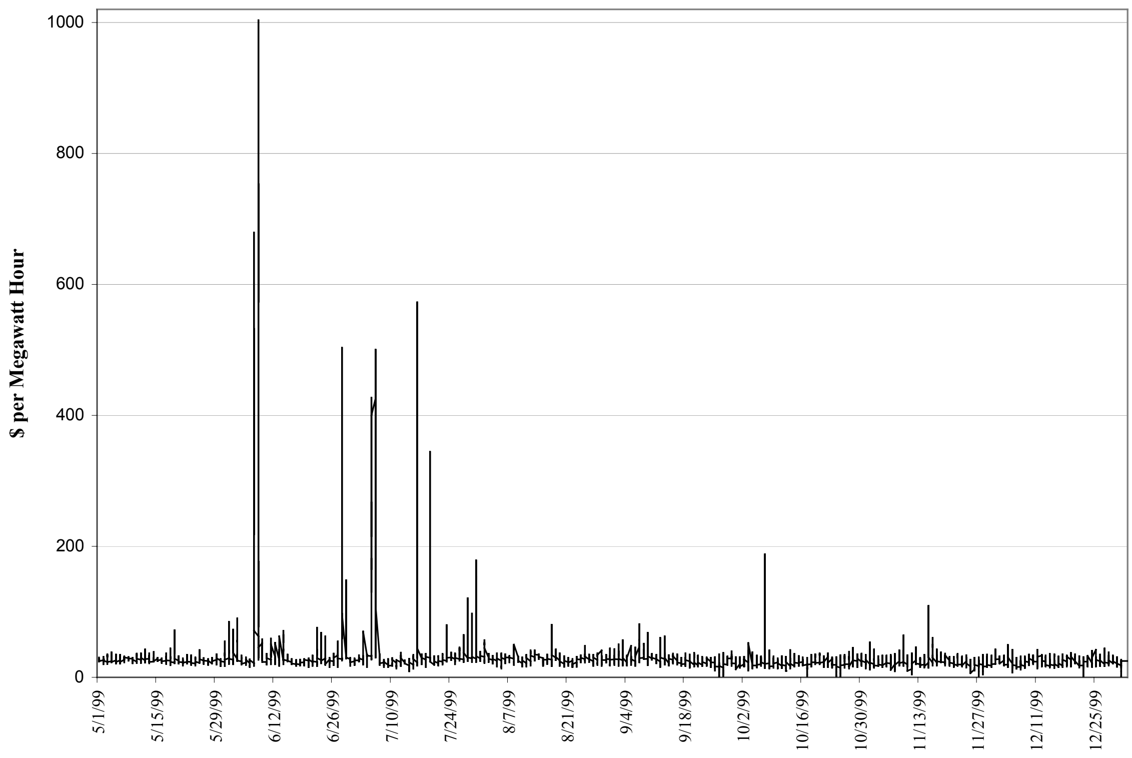


Source: ISO-New England

Price volatility occurs when the capacity margin is thin.

Figure 15 illustrates hourly price fluctuations in New England electricity markets in 1999. The significant volatility occurred during peak summer months when capacity was scarce relative to demand. For the spot market to become truly competitive, customers must begin to see these prices and adjust their behavior accordingly. Customers can either reduce demand or self-supply their electricity when prices rise above the marginal value of the electricity. The development of price-sensitive consumption will require investment in time-of-use meters and better information about energy costs.

Figure 15: Hourly Price Volatility in New England Wholesale Electricity Markets, 1999

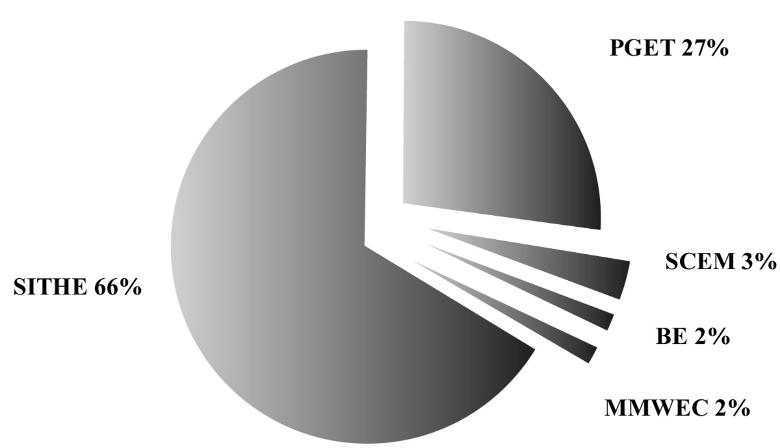


Source: ISO-New England

Market rules limit wholesale prices in transmission constrained areas.

Generation ownership[43] is highly concentrated within certain areas of the New England region. The vertically integrated utilities that built the transmission system planned to supply their native load with their own generation. As a result, areas with limited transmission capacity, such as the Northeastern Massachusetts (NEMA) area, can become transmission constrained to the point that additional energy cannot be imported. This mattered little when generation was sold at regulated rates. However, it becomes very difficult to develop competition

Figure 16: 1999 Generation Capacity Ownership in Northeastern Massachusetts Zone



Source: NEPOOL

[43] List of abbreviations: Boston Edison Co. (BE), PG&E Energy Trading L.P. (PGET), Sithe New England Holdings (SITHE), Massachusetts Municipal Wholesale Elect. Co. (MMWEC), Southern Co. Energy Marketing (SCEM).

inside a congested zone when generation is dominated by a single supplier, as in the NEMA territory. Because most of the generation inside NEMA is owned by a single supplier (Figure 16), there are many hours when energy and especially ancillary services cannot be competitively supplied in the zone.

The ISO-NE's market rules allow it limited ability to constrain market prices when competition ceases to exist. ISO-NE invoked this administrative power on many occasions in 1999. In the long-term, the solution to locational market dominance is to develop more competitive generation inside, or greater transmission capacity into, that region. In New England, the ability for the spot market to stay competitive will depend largely upon the ability of generation capacity to stay ahead of peak demand.

4.5 Wholesale Market Reliability

Reliability standards were maintained.

Even with the advent of a wholesale market for electricity, NEPOOL still adhered to the same reliability standards, as defined by the North American Electricity Reliability Council (NERC). These standards defined how many megawatts of capacity the power pool must keep in reserve in the event of an emergency. NEPOOL also sets its own "Objective Capability" standards to meet expected peak system demand.

During the summer of 1999, system reliability was tested several times.

On June 8th and 9th, the region suffered a severe capacity shortage from several unexpectedly hot days coincident with generator outages. In neither of these instances did the new market reduce short-term system reliability. The system operator (ISO-NE) had to call all of its emergency reserves, but was able to maintain system integrity. When systems reserves are expected to fall below standard, the ISO-NE will implement Operating Procedure Number 4 (OP 4) to increase system capacity. Under various emergency conditions, ISO-NE has the authority to procure emergency power from other power pools and perform other activities that increase supply or decrease demand. Historically, NEPOOL has had more installed resources than required to meet objective capability. In addition, it has managed its generator maintenance scheduling to maximize the resources available during peak load periods. In 1999 there were eleven days when OP 4 was implemented, as the system was stretched in June and July.

Table 14: OP 4 Events, 1991-1999

Year	Number of Events
1991	5
1992	2
1993	1
1994	2
1995	9
1996	2
1997	5
1998	5
1999	11

Source: ISO-NE

4.6 Market Problems Experienced in 1999

The new market's performance in 1999 illuminated imperfections in the system and the need for further modifications. For example, ISO-NE had to adjust prices often in the new markets because of reasons such as human error, software flaws, and market failures. There were 620 price corrections in 1999, mostly in the operating reserves markets.[44] Market rule flaws also contributed to market price volatility during the year. A lot of progress was made in the design of a better functioning system that ultimately will send proper price signals to all participants. Throughout the year, ISO-NE and the NEPOOL Participants' Committee enacted multiple rule changes in attempts to make rule corrections; however, some problems will take more time to resolve and are discussed below. [45]

There is a relatively low number of flexible (quick start) units.

Electricity markets are physically constrained by their generation asset mix. There are relatively few flexible ("quick start") generating units in New England. Because it needs to hold some quick start generating units in reserves for a contingency, the system operator regularly opts to run inflexible units at their lower operating limit to provide needed reserves. This creates sufficient reserves to meet reliability standards but does not promote market efficiency or equality: inflexible units are over-compensated while flexible units are under-compensated.

More expensive generating units were dispatched in transmission constrained areas.

Another physical impediment to the energy market is the transmission system. Some parts of New England, such as Boston, did not have sufficient transmission capacity to meet demand for electricity from competitive resources during periods of peak demand. Therefore, to meet local demand the system operator was forced to operate more expensive generators than would be necessary if the transmission constraint did not exist. Because of this problem, a generator in a transmission-constrained region has local market power, and the price it is paid for its energy must be restricted ("mitigated") by the system operator. This creates two additional problems: first, whenever a high-cost generator runs out-of-merit, a lower cost generator loses a deserved opportunity to receive revenue, and second, the higher costs are socialized among the entire power pool, which sends the wrong demand signals to the load.

There is a need for day-ahead settlement.

Even before the new competitive wholesale market system was implemented, the lack of a day-ahead settlement was identified as an important market design flaw. Bids for energy and ancillary services are submitted to the system operator the day ahead, but are not settled (i.e. not financially binding) until the real-time demand is known. This process makes it impossible to hedge demand because true energy clearing prices are not known until the power flows. Generators are not bound to their bids in the day-ahead. This market flaw was not considered significant before the market began, but it became more apparent how important a true forward market is to stable prices when unexpected demand and generator outages began to create price spikes. Price volatility is compounded by the lack of demand responsive resources that are willing and able to reduce demand in response to high prices.

[44] ISO New England, Annual Market Report, May 1999 - April 2000

[45] The NEPOOL Participants Committee is the governance structure of the regional electric power system.

4.7 Market Re-designs and Developments

Open, competitive markets are the most effective method for consistently finding the most efficient allocation of resources. The fundamental market tenets are to avoid discrimination and provide transparent prices. However, electricity is a unique product because the supply and demand must be kept in constant balance. A localized imbalance can disable an entire electric power system. The wholesale market for electricity must be carefully designed to create the right economic signals while preserving system reliability. Getting the incentives right has been a challenge wherever electric power services have been liberalized.

In New England, a lack of price transparency resulted in a host of incorrect price signals. In addition, nationally, the FERC recognized that discriminatory access to the bulk power transmission system was hindering competition. In response to these issues, the ISO-NE and the NEPOOL participants undertook two important market re-design efforts in 1999.

Regionally, NEPOOL participants struggled to redefine the wholesale market by creating a Congestion Management System (CMS) and a Multi-Settlement System (MSS). In addition, the FERC conducted a public inquiry into opening access to the bulk power transmission system and power markets through the development of Regional Transmission Organizations (RTOs).

A wholesale market re-design through a congestion management and multi-settlement system was undertaken.

As previously mentioned, even before the start of the wholesale market in May 1999, the market participants were aware of flaws in the market design. An independent consultant[46] sponsored by the ISO-NE evaluated market flaws and identified four major recommendations:

- Switch to a multi-settlement system;
- Introduce demand-side bidding;
- Adopt locational-based transmission congestion pricing; and
- Change the way spinning reserves are priced.

To address the flaws in its markets, NEPOOL organized a committee to develop market rules and tariffs for both a congestion management system and multi-settlement system (CMS/MSS), with a self-imposed deadline of the end of 1999.

Multi-settlement is the process of settling energy trades in multiple time frames. The Multi-settlement proposal for New England would provide a day-ahead settlement, and a real-time settlement. The expectation is that most of the load will settle in the day-ahead market as both buyers and sellers will prefer the stability of a day-ahead commitment. In the market system implemented in 1999, there was a day-ahead forecast but it was not financial binding and the prices can often varied significantly depending upon the supply and demand balance in real time. Day-ahead settlement will create financially binding obligations, ensuring a price for all

[46] Crampton, Peter and Wilson, Robert. "A Review of ISO New England's Proposed Market Rules." September 9, 1998. Page 1.

load that settles and will greatly increase the ability of consumers to adjust their demand to price signals. Any load that does not settle in the day-ahead will still settle in the spot market.

As proposed by NEPOOL and the ISO-NE, the Congestion Management System places a financial value on transmission congestion. When transmission congestion exists (the price of energy in zone A becomes greater than in zone B) the holders of the Financial Congestion Rights (FCRs) across the congested transmission ties will be paid the price differential between the zones as a product of the amount of FCRs held. The proposed congestion management system allocates congestion costs to those customers in the congested areas and allows suppliers to hedge some of their price risks. By assessing the cost of transmission congestion, customer loads in congested zones can be managed, supply costs can be hedged, and investment needs can be identified. However, it does not provide a mechanism to mitigate congestion in real time.

For consumers inside congested zones there will be a price rise when CMS is implemented, as the previously socialized congestion costs are absorbed only regionally. The Northeastern Massachusetts (NEMA) zone, which includes Boston, will likely see a price rise due to congestion. Much of the generation inside the NEMA zone is expensive and there is insufficient transmission capacity to meet the demand with resources outside the zone.

The CMS/MSS filing was not completed by the end of 1999 and was filed with the FERC in 2000. DOER's 2000 Market Monitor will continue the discussion and analysis of the CMS/MSS filing.

Regional Transmission Organizations

In 1999, the FERC proposed to amend its regulations under the Federal Power Act (FPA) to facilitate the formation of Regional Transmission Organizations (RTOs). The stated objective is for all electric utilities in the United States to place their transmission facilities in an independently managed transmission entity to promote both system reliability and competitive generation markets. The FERC asserted that incompatible rules between control areas and discriminatory access by transmission owners has hindered the development of a true interstate market for electric power.

Equally important the FERC recognized the conflict of interest when a transmission owner also participates in the electric power market. Transmission capacity is limited, and the limits are dynamic. When a transmission owner decides to place a limit on its transmission capacity, add transmission capacity, or take a transmission line out for service, it can have an impact on electricity prices. As capacity is limited, power marketers must compete to gain access to the transmission. A transmission owner that is also in the business of power generation and power marketing will naturally be inclined to favor its own transactions over the transactions of others.

The FERC had already mandated an Open Access Same-time Information System (OASIS) in a previous order (Order # 888) to provide all participants access to information on the availability of transmission capacity. However, advance notice of planning and maintenance and other information can have a large commercial value to energy marketers. On December 15, 1999, in an attempt to further free the electric power market for competition, the FERC ordered (Order # 2000) that all transmission owners join an RTO. Much of the wholesale chapter in the 2000 Market Monitor will focus on the impacts of FERC Order 2000 in New England.

4.8 Outstanding Wholesale Market Issues

For Massachusetts, two local issues will have a large impact on the future development of the wholesale market: load response and transmission constraints. ISO-NE and NEPOOL are addressing both of these issues.

Consumers need an effective demand response market.

In order for consumers (commercial, industrial and residential) to respond effectively to energy demand and prices, they must be able to see both the future and the real-time cost of energy consumption and the financial benefit of responding to price signals. The introduction of day-ahead market settlement for energy will provide the opportunity to capture some of the financial benefits of load response. The financial benefit can be gained by reducing demand when prices are high. What is additionally required is a link between consumers, suppliers, and the market. The Internet provides opportunities to transmit price and demand data cost-effectively. It is essential for customers, regulators, and electric distribution companies to agree on a new open-access standard for the customers' metered demand. Providing open access to the wholesale market will give consumers little or no benefit without open access at the retail level.

Monitoring of wholesale market transactions must be enhanced.

If all consumers in Massachusetts are to benefit from competitive wholesale markets, sufficient competition must be present to prevent market power abuse. The concentration of ownership and lack of regional transmission constraints may inhibit the development of a truly competitive market in New England. The market is also susceptible to gaming behavior by market participants that may want to take advantage of market flaws, poor information flows, and market rule differences between neighboring control areas. The ISO-NE has direct responsibility for monitoring the wholesale markets; however, there is concern that ISO-NE has neither the geographic scope nor the resources necessary to monitor all potential market abuses.

The changing landscape of the wholesale electricity industry has revealed market flaws even as it has created new opportunities and incentives for improvement. DOER will continue its analyses of these and other wholesale issues in its Market Monitor 2000.

Conclusion

The ability of the wholesale electric power market to deliver the proper price signals is an area of continued concern in New England. The NEPOOL Participants Committee and the ISO-NE made a considerable effort in 1999 to agree on new market and congestion management mechanisms. NEPOOL was required by the FERC to submit new market rules and tariffs for a Multi-Settlement and Congestion Management System to replace the interim market. Until market design flaws can be resolved, buyers in New England can expect to be exposed to continuing price volatility. However, many of the market problems should continue to be mitigated by regulatory action and the ISO-NE.

V. OUTLOOK FOR 2000

The second year of restructured electric markets in Massachusetts sent mixed messages to the industry and its customers. Retail prices fell, but price disparities did not change. Competitive suppliers sought licenses from the DTE and standard offer and default service rates increased, but competition did not flourish. A wholesale market opened, but wholesale prices demonstrated dramatic volatility. The 2000 Market Monitor will continue DOER's examination of the continued progress of electric industry restructuring. Specific events and topics that will be addressed in the 2000 report include the following:

FERC Order 2000

In its December 1999 order, the Federal Energy Regulatory Commission set a mandate for all regions in the United States to develop regional transmission organizations to control the operation of the power grid. DOER's 2000 Market Monitor will report on ISO-New England's efforts to comply with the requirements of the order.

Default Service Decoupling

2000 brought the decoupling of standard offer and default service rate structures in Massachusetts. In its set of orders under the general title DTE 99-60, the Department of Telecommunications and Energy allowed default service rates to reflect market prices, while keeping standard offer rates set by approved rate schedules.

E-Commerce and Retail Competition

In 2000, retail competition showed significant activity over the Internet. Several e-commerce operations offered competitive electricity products to Massachusetts residents and businesses during the year. The 2000 report will examine successes and challenges of these innovative retail options.

Merger Outcomes

DOER will look at the final outcomes of the three mergers discussed in this year's report, and will survey the impacts of these mergers on the retail industry.

Fuel Prices and Electric Rates

Higher prices of natural gas and oil translated into higher costs for electric generation. 2000 saw public debate over whether or not utilities could pass these higher costs along to the customer.

Wholesale Market Reforms

Through the identification of flaws in the wholesale power system, ISO-New England and NEPOOL drafted a proposal for the implementation of Congestion Management and Multi-Settlement Systems. The two entities filed the proposal with the FERC in the beginning of 2000. The 2000 Market Monitor will pick up where the discussion of the CMS/MSS in Chapter IV left off, and will look at the ability of the proposal to resolve the perceived flaws.

Service Quality Indicators

In order to ensure that utility consolidation did not result in poorer customer service, regulators established performance standards by which utilities could be evaluated. Next year's report will monitor the success of this policy strategy.

MBIS
Metering and Billing Information Systems occupied a significant role in the industry's public debate in 2000. The Act required the DTE to rule on the "unbundling" of MBIS systems under deregulation. The 2000 report will present various stakeholder views as well as the DTE's actions on the matter.

Competitive Market Development
DOER will continue to monitor activity within the retail electric industry. The 2000 report will analyze the results of DOER's ongoing customer migration surveys, indicating the flux of electricity customers from standard offer, default service, and competitive supply.

Conclusion

Ratepayer data confirms that Massachusetts utility companies met the promise of lower rates during the first two years of electric restructuring. Massachusetts electric customers saved approximately $535 million in 1999, bringing the combined total savings from 1998 and 1999 to $910 million. However, minimal movement towards competitive suppliers indicates that the success of deregulation is mixed: only 0.3 percent of customers exercised the option to switch from standard offer and default service. Still, this 0.3 percent consumed 9.2 percent of the electricity sold by competitive suppliers in the Commonwealth. This indicates that large customers were indeed taking advantage of restructuring's offerings.

The wholesale market developments of 1999 offers hope of an efficient system that is responsive to the market forces of supply and demand. Yet, concerns over price volatility and customer response must be addressed for this to occur. Above all other concerns lies system reliability and the need for increased capacity to meet growing demand.

The decidedly mixed outcomes of 1999 speak to the complex nature of electric markets and to the many ways in which the success of restructuring can be measured. The markets for electricity, both retail and wholesale, will be sorted out slowly in the coming years as pieces of the puzzle fall into place. The years ahead will provide answers to many of the questions that existed in 1999, but will also uncover questions of their own.

APPENDIX: Customer Migration Figures, April and December 1999

BOSTON EDISON

April 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	443,744	235,420,198	93,511	35,266,311	744	695,462
Residential -- Low Income	26,819	11,051,473	2,215	955,122	0	0
Small Commercial & Industrial	47,404	34,438,563	7,698	5,609,389	506	366,300
Medium Commercial & Industrial	24,177	186,962,029	2,893	15,239,004	477	5,087,413
Large Commercial & Industrial	1,801	363,587,622	217	24,395,360	141	45,403,157
Farms	0	0	0	0	0	0
Street Lights	5,408	10,533,917	183	76,908	277	363,443
Total Sales	**549,353**	**841,993,802**	**106,717**	**81,542,094**	**2,145**	**51,915,775**

December 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	422,788	244,369,553	141,734	59,367,928	1,335	1,477,385
Residential -- Low Income	28,157	12,243,393	2,657	1,523,301	0	0
Small Commercial & Industrial	45,018	32,003,160	11,858	8,195,596	995	750,816
Medium Commercial & Industrial	21,577	163,947,221	4,363	25,926,781	986	11,354,146
Large Commercial & Industrial	1,780	342,817,222	370	47,256,972	353	113,367,368
Farms	0	0	0	0	0	0
Street Lights	6,591	11,839,966	319	172,801	634	2,566,017
Total Sales	**525,911**	**807,220,515**	**161,301**	**142,443,379**	**4,303**	**129,515,732**

Source: DOER Form 110

APPENDIX: Customer Migration Figures, April and December 1999

CAMBRIDGE ELECTRIC

April 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	28,292	9,736,066	9,405	2,488,298	0	0
Residential -- Low Income	1,370	431,572	37	10,724	0	0
Small Commercial & Industrial	3,924	3,205,169	433	428,514	8	2,396
Medium Commercial & Industrial	1,896	13,707,174	286	2,132,722	0	0
Large Commercial & Industrial	294	60,754,254	60	7,711,703	4	795,275
Farms	0	0	0	0	0	0
Street Lights	220	450,755	45	9,703	0	0
Total Sales	**35,996**	**88,284,990**	**10,266**	**12,781,664**	**12**	**797,671**

December 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	21,349	6,625,177	11,837	3,162,827	0	0
Residential -- Low Income	1,140	342,976	36	11,790	0	0
Small Commercial & Industrial	3,379	2,406,665	568	387,534	8	2,944
Medium Commercial & Industrial	1,786	9,376,836	419	2,173,937	0	0
Large Commercial & Industrial	257	54,686,358	84	10,828,977	0	0
Farms	0	0	0	0	0	0
Street Lights	201	638,171	42	13,297	0	0
Total Sales	**28,112**	**74,076,183**	**12,986**	**16,578,362**	**8**	**2,944**

Source: DOER Form 110

APPENDIX: Customer Migration Figures, April and December 1999

COMMONWEALTH ELECTRIC

April 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	252,882	107,279,720	30,665	10,869,865	1	77
Residential -- Low Income	15,837	6,817,780	566	212,401	0	0
Small Commercial & Industrial	32,974	63,887,381	4,451	4,584,022	185	1,109,099
Medium Commercial & Industrial	405	33,167,785	13	1,103,464	27	3,307,956
Large Commercial & Industrial	64	31,215,166	0	0	4	5,708,040
Farms	0	0	0	0	0	0
Street Lights	5,019	1,454,683	244	22,879	56	21,609
Total Sales	**307,181**	**243,822,515**	**35,939**	**16,792,631**	**273**	**10,146,781**

December 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	213,395	110,392,523	41,491	18,523,528	2	157
Residential -- Low Income	13,915	6,803,854	466	204,955	0	0
Small Commercial & Industrial	28,691	60,899,509	6,039	8,938,584	321	1,328,871
Medium Commercial & Industrial	353	28,737,658	20	1,760,442	28	3,313,905
Large Commercial & Industrial	57	28,303,804	0	0	6	710,280
Farms	0	0	0	0	0	0
Street Lights	4,418	2,029,200	359	57,547	69	50,033
Total Sales	**260,829**	**237,166,548**	**48,375**	**29,485,056**	**426**	**5,403,246**

Source: DOER Form 110

APPENDIX: Customer Migration Figures, April and December 1999

EASTERN UTILITIES

April 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	132,237	72,536,452	15,888	5,561,824	0	0
Residential -- Low Income	14,362	5,804,352	115	42,297	0	0
Small Commercial & Industrial	14,385	8,212,617	2,289	1,414,327	6	7,898
Medium Commercial & Industrial	6,165	67,130,429	610	5,733,125	14	391,633
Large Commercial & Industrial	125	42,900,354	4	458,400	1	359,100
Farms	140	249,772	4	2,835	0	0
Street Lights	0	1,825,287	0	74,389	0	151,715
Total Sales	**167,414**	**198,659,263**	**18,910**	**13,287,197**	**21**	**910,346**

December 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	126,472	81,413,825	23,173	10,264,307	2	4,102
Residential -- Low Income	13,593	6,197,601	327	130,577	0	0
Small Commercial & Industrial	13,444	7,999,643	3,496	1,848,778	148	291,006
Medium Commercial & Industrial	5,931	66,411,706	880	7,906,585	98	2,225,186
Large Commercial & Industrial	121	43,769,548	9	901,740	1	405,300
Farms	128	195,895	6	2,696	0	0
Street Lights	0	2,724,932	0	105,044	0	272,416
Total Sales	**159,689**	**208,713,150**	**27,891**	**21,159,727**	**249**	**3,198,010**

Source: DOER Form 110

APPENDIX: Customer Migration Figures, April and December 1999

FITCHBURG GAS AND ELECTRIC

April 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	20,052	9,981,471	2,284	809,156	1	626
Residential -- Low Income	1,150	605,340	14	49,727	0	0
Small Commercial & Industrial	1,269	373,887	81	51,451	14	3,190
Medium Commercial & Industrial	1,494	7,102,874	125	479,097	21	161,863
Large Commercial & Industrial	27	14,783,137	5	1,438,598	0	0
Farms	34	89,281	0	0	0	0
Street Lights	568	225,329	23	6,815	2	4,459
Total Sales	**24,594**	**33,161,319**	**2,532**	**2,834,844**	**38**	**170,138**

December 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	19,209	11,486,053	3,077	1,432,293	1	716
Residential -- Low Income	1,071	473,650	11	31,436	0	0
Small Commercial & Industrial	1,253	327,143	152	63,759	13	4,690
Medium Commercial & Industrial	1,482	7,892,870	161	708,423	19	177,446
Large Commercial & Industrial	51	19,739,384	0	0	0	0
Farms	16	39,632	0	0	0	0
Street Lights	567	289,108	35	8,713	9	19,318
Total Sales	**23,649**	**40,247,840**	**3,436**	**2,244,624**	**42**	**202,170**

Source: DOER Form 110

APPENDIX: Customer Migration Figures, April and December 1999

MASSACHUSETTS ELECTRIC

April 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	718,810	393,932,558	108,199	42,561,037	531	311,748
Residential -- Low Income	47,085	21,462,098	0	0	1	0
Small Commercial & Industrial	80,916	98,167,425	12,549	13,305,812	1,927	1,632,747
Medium Commercial & Industrial	9,501	158,934,994	849	13,042,747	329	5,330,554
Large Commercial & Industrial	1,769	444,955,941	136	15,009,017	237	65,912,184
Farms	0	0	0	0	0	0
Street Lights	714	6,784,600	22	144,486	79	1,408,334
Total Sales	**858,795**	**1,124,237,616**	**121,755**	**84,063,099**	**3,104**	**74,595,567**

December 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	674,712	461,257,408	156,687	79,197,123	571	624,693
Residential -- Low Income	47,649	26,090,162	0	0	1	1,517
Small Commercial & Industrial	75,540	107,664,477	18,983	24,318,425	2,475	3,397,536
Medium Commercial & Industrial	8,935	164,066,567	1,210	22,366,013	526	11,602,628
Large Commercial & Industrial	1,677	388,531,356	222	34,855,489	292	165,329,906
Farms	0	0	0	0	0	0
Street Lights	677	9,418,433	27	357,852	106	2,773,115
Total Sales	**809,190**	**1,157,028,403**	**177,129**	**161,094,902**	**3,971**	**183,729,395**

Source: DOER Form 110

APPENDIX: Customer Migration Figures, April and December 1999

NANTUCKET ELECTRIC

April 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	7,818	4,442,868	1,226	674,984	0	0
Residential -- Low Income	42	35,473	0	0	0	0
Small Commercial & Industrial	929	1,143,440	120	78,763	0	0
Medium Commercial & Industrial	51	914,011	0	0	0	0
Large Commercial & Industrial	3	349,880	0	0	0	0
Farms	0	0	0	0	0	0
Street Lights	2	19,484	2	62	0	0
Total Sales	**8,845**	**6,905,156**	**1,348**	**753,809**	**0**	**0**

December 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	7,558	5,135,301	1,806	1,179,517	0	0
Residential -- Low Income	41	33,522	0	0	0	0
Small Commercial & Industrial	898	1,341,287	272	212,956	0	0
Medium Commercial & Industrial	53	1,036,472	0	0	0	0
Large Commercial & Industrial	3	389,200	0	0	0	0
Farms	0	0	0	0	0	0
Street Lights	2	30,060	2	96	0	0
Total Sales	**8,555**	**7,965,842**	**2,080**	**1,392,569**	**0**	**0**

Source: DOER Form 110

APPENDIX: Customer Migration Figures, April and December 1999

WESTERN MASSACHUSETTS ELECTRIC

April 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	137,427	68,707,181	23,509	8,375,446	0	0
Residential -- Low Income	15,915	7,439,442	2	1,023	0	0
Small Commercial & Industrial	15,082	32,886,423	1,900	2,763,817	1	2,224
Medium Commercial & Industrial	1,214	35,127,684	69	1,376,384	0	0
Large Commercial & Industrial	273	108,071,130	6	1,173,480	0	0
Farms	528	1,266,402	11	10,879	0	0
Street Lights	1,070	2,025,371	177	415,826	9	93,211
Total Sales	**171,509**	**255,523,633**	**25,674**	**14,116,855**	**10**	**95,435**

December 1999

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	129,837	65,902,514	32,788	12,318,740	0	0
Residential -- Low Income	15,234	6,544,887	2	1,546	0	0
Small Commercial & Industrial	14,303	30,307,779	2,812	4,488,031	2	2,650
Medium Commercial & Industrial	1,097	30,515,090	126	2,438,057	0	0
Large Commercial & Industrial	255	97,514,031	12	2,347,308	0	0
Farms	532	1,109,926	19	199,851	0	0
Street Lights	1,226	2,050,575	254	295,036	8	76,079
Total Sales	**162,484**	**233,944,802**	**36,013**	**22,088,569**	**10**	**78,729**

Source: DOER Form 110